PB84-215755

Methods for Determining the Mechanical Integrity of Class II Injection Wells

National Water Well Association, Worthington, OH

Prepared for

Robert S. Kerr Environmental Research Lab.
Ada, OK

Jul 84

U.S. Department of Commerce
National Technical Information Service
NTIS

PB84-215755

EPA-600/2-84-121
July 1984

METHODS FOR DETERMINING THE MECHANICAL INTEGRITY OF CLASS II INJECTION WELLS

by

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Cooperative Agreement CR-809353

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SPRINGFIELD, VA. 22161

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-600/2-84-121	2.	3. RECIPIENT'S ACCESSION NO. PB84-215755
4. TITLE AND SUBTITLE Methods for Determining the Mechanical Integrity of Class II Injection Wells		5. REPORT DATE July 1984 6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) David M. Nielsen and Linda Aller		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS National Water Well Association 500 West Wilson Bridge Road Worthington, OH 43085		10. PROGRAM ELEMENT NO. ABPC1A/CBPC1A 11. CONTRACT/GRANT NO. CR-809353
12. SPONSORING AGENCY NAME AND ADDRESS U.S. Environmental Protection Agency R.S. Kerr Environmental Research Laboratory P.O. Box 1198 Ada, OK 74820		13. TYPE OF REPORT AND PERIOD COVERED Final 14. SPONSORING AGENCY CODE EPA 600/15

15. SUPPLEMENTARY NOTES

16. ABSTRACT

The mechanical integrity of injection wells must be determined to insure that there is no significant leak in the casing, tubing or packer, and that there is no significant fluid movement through vertical channels adjacent to the injection well.

Methods for mechanical integrity testing include monitoring of annulus pressure, pressure testing, temperature logging, noise logging, pipe analysis surveys, electromagnetic thickness surveys, caliper logging, borehole television, borehole televiewer, flowmeter surveys, radioactive tracer surveys and cement bond logging. Only temperature logging, noise logging and radioactive tracer surveys can be used to provide relatively definitive information regarding the presence or absence of fluid movement behind casing; cement bond logs provide information from which fluid movement may be inferred. With the exception of cement bond logging, all of the testing methods can be used to locate leaks in casing. This document describes each of the methods that can be used in mechanical integrity testing, including principles, equipment, procedures, interpretation, cost, advantages, disadvantages, and examples of each technique.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Injection wells oil well cementing cement bonding plugging radioactive well logging temperature well logging		Water pollution and control

18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS (This Report) Unclassified	21. NO. OF PAGES 281
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (9-73)

DISCLAIMER

Although the research described in this report has been funded wholly or in part by the United States Environmental Protection Agency through cooperative agreement CR-809353 to East Central University Environmental Research Institute, it has not been subjected to the agency's peer and policy review and therefore does not necessarily reflect the views of the agency and no official endorsement should be inferred, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

FOREWORD

The Environmental Protection Agency was established to coordinate administration of the major Federal programs designed to protect the quality of our environment.

An important part of the Agency's effort involves the search for information about environmental problems, management techniques and new technologies through which optimum use of the Nation's land and water resources can be assured and the threat pollution poses to the welfare of the American people can be minimized.

EPA's Office of Research and Development conducts this search through a nationwide network of research facilities.

As one of these facilities, the Robert S. Kerr Environmental Research Laboratory is the Agency's center of expertise for investigation of the soil and subsurface environment. Personnel at the laboratory are responsible for management of research programs to: (a) determine the fate, transport and transformation rates of pollutants in the soil, the unsaturated zone and the saturated zones of the subsurface environment; (b) define the processes to be used in characterizing the soil and subsurface environment as a receptor of pollutants; (c) develop techniques for predicting the effect of pollutants on ground water, soil and indigenous organisms; and (d) define and demonstrate the applicability and limitations of using natural processes, indigenous to the soil and subsurface environment, for the protection of this resource.

This report contributes to that knowledge which is essential in order for EPA to establish and enforce pollution control standards which are reasonable, cost effective and provide adequate environmental protection for the American public.

Clinton W. Hall

Clinton W. Hall
Director
Robert S. Kerr Environmental
Research Laboratory

PREFACE

Methods for Determining the Mechanical Integrity of Class II Injection Wells has been developed under the guidance of East Central Environmental Research Institute, in conjunction with the U.S. Environmental Protection Agency, for use by all of those involved in efforts to determine the mechanical integrity of injection wells. Techniques described are those which are currently in use and methods which may be of future significance.

For those concerned with protecting ground water, this document may be helpful as a ready summary of ways to help ensure that injection wells do not have a leak in the casing, tubing or packer and that no significant fluid movement behind the casing exists. Finally, this manual partially fulfills a mandate contained in the Safe Drinking Water Act (P.L. 93-523) requiring the Administrator of the Environmental Protection Agency to "...carry out a study of methods of underground injection which do not result in the degradation of underground drinking water sources."

ABSTRACT

The Underground Injection Control program regulations, administered by the U.S. Environmental Protection Agency, require injection well operators to test the mechanical integrity of injection wells, including those wells that inject fluids 1) brought to the surface during oil and gas production, 2) for enhanced recovery of oil and gas and 3) for storage of hydrocarbons in the subsurface (Class II wells). Testing is required to satisfy the regulatory requirement that there is no significant leak in the casing, tubing or packer, and that there is no significant fluid movement through vertical channels adjacent to the injection well.

There are a number of methods available to injection well operators for mechanical integrity testing. These include monitoring of annulus pressure, pressure testing, temperature logging, noise logging, pipe analysis surveys, electromagnetic thickness surveys, caliper logging, borehole television, borehole televiewer, flowmeter surveys, radioactive tracer surveys and cement bond logging. Only temperature logging, noise logging and radioactive tracer surveys can be utilized to provide relatively definitive information regarding the presence or absence of fluid movement behind casing; cement bond logs provide information from which fluid movement may be inferred. With the exception of cement bond logging, all of the testing methods can be used to locate leaks in casing.

This document describes each of the methods that can be used in mechanical integrity testing in detail, including the principles, equipment, procedures, interpretation, cost, advantages and disadvantages and examples of each technique. Other methods which may also have application in mechanical integrity testing, but which require additional field testing to establish their effectiveness, are also described. Many of the described mechanical integrity tests are not adaptable to the testing of hydrocarbon storage well systems. During the last few years, rapid development of specialized testing procedures has changed the state of the art considerably. Therefore, a discussion of storage well testing methods is not included in this document.

This report was submitted in partial fulfillment of Contract No. CR-809353 by the National Water Well Association under the sponsorship of the Robert S. Kerr Environmental Research Laboratory, Ada, Oklahoma and in cooperation with East Central University Environmental Research Institute, Ada, Oklahoma. This report covers a period from December, 1981, to December, 1983, and work was completed as of December, 1983.

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ACKNOWLEDGEMENTS

This document reflects the state of the art available today on methods for determining the mechanical integrity of Class II injection wells. It is the product of many experiences, some published and some unpublished. Its successful completion, however, is due to the time and effort which an unusually able advisory review panel was willing to devote to this activity. To the following named persons, grateful acknowledgement of their contributions is made:

Ray Alred
Research Services Division
Conoco Inc.

Richard Benson
Technos, Inc.

Bill G. Cantrell
Oil Operator

Timothy Dowd, Executive Director
Interstate Oil Compact Commission

W. Scott Keys
U.S. Geological Surey

T. A. Minton
Oklahoma Corporation Commission

Joe G. Moore
University of Texas at Dallas

Jerry Mullican
Texas Railroad Commission

Robert Phillips
Shell Oil Company

Larry Sowell
Gearhart Industries

John S. Talbot
Baffin Associates

SECTION 1

INTRODUCTION

OBJECTIVES AND SCOPE

Methods for Determining the Mechanical Integrity of Class II Injection Wells has been prepared as an aid to state and federal authorities involved in administering the regulations pertaining to the mechanical integrity of Class II injection wells under the Underground Injection Control Program (UIC). This report is also designed to assist industry representatives, injection well operators, engineers and others with the task of ensuring the mechanical integrity of those injection wells. While this report is intended to apply specifically to Class II wells, the technology described herein may also be applicable to other classes of injection wells.

This report is intended to be informative rather than prescriptive in nature. The basic objective is to provide a concise description of methods or technologies which are currently being used or which may have applicability in determining the mechanical integrity of injection wells.

In developing Methods for Determining the Mechanical Integrity of Class II Injection Wells, past, present and potentially available methods for determining the mechanical integrity of injection wells were researched. A review of the available literature revealed that a significant amount of information has been written about the testing of wells for downhole problems such as leaks in the casing or flow behind the casing. However, most of the work described in the literature has involved the testing and inspection of producing oil and gas wells rather than injection wells. Fortunately, most of this technology is also applicable to injection wells.

To better determine the state-of-the-art, government officials in oil and gas producing states were surveyed regarding regulations, requirements, methods and procedures used to determine mechanical integrity of injection wells. Efforts to document the applicability of many types of services provided by well logging companies were also conducted.

Impetus for the development of *Methods for Determining the Mechanical Integrity of Class II Injection Wells* was provided by passage of Public Law 93-523 (the Safe Drinking Water Act) and the subsequent enactment of federal regulations found in 40 CFR Parts 122, 123, 124 and 146 (the UIC Program). The Safe Drinking Water Act of 1974 requires the U.S. Environmental Protection Agency to develop minimum requirements to assist in the establishment of effective state programs to protect underground sources of drinking water from contamination resulting from the subsurface emplacement of fluids through well injection. Additionally, the Act states that these requirements not impede the re-injection of brine or other fluids resulting from oil and natural gas production or the injection of fluids used in secondary or tertiary recovery unless drinking water sources would be endangered (Federal Register, June 24, 1980).

40 CFR Parts 122, 123, 124 and 146, (the UIC Program) were enacted under the authority of PL 93-523. 40 CFR Part 122 defines the regulatory framework of EPA-administered permit programs; 40 CFR Part 123 describes the elements of an approved state program and criteria for EPA approval of that program; 40 CFR Part 124 describes the procedures the agency will use for issuing permits under covered programs; and 40 CFR Part 126 sets forth technical criteria and standards for the UIC (Federal Register, June 24, 1980; Federal Register, February 3, 1982). A discussion of some of the pertinent sections of 40 CFR Part 146 are described below.

Underground injection is defined as the subsurface emplacement of fluids through a well (146.03). For purposes of the UIC program, injection wells were classified into five categories based on the nature of the fluid which would be injected. In general, Class I wells include industrial and municipal disposal wells and hazardous waste disposal wells not covered in Class IV; Class II wells include wells which inject fluids 1) brought to the surface during oil and gas production, 2) for enhanced recovery of oil and gas, or 3) for storage of hydrocarbons which are liquid at standard temperature and pressure; Class III wells inject for the purpose of extraction of minerals or energy; Class IV wells include disposal wells used by hazardous and radioactive waste generators and disposal site operators; Class V includes injection wells not covered by the four other classes (146.05).

Inherent in the permit process for each of these classes of wells is the determination of the mechanical integrity of the injection well. An injection well is determined to have mechanical integrity when it meets both of the following criteria: 1) there is no significant leak in the casing, tubing or packer; and 2) there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well (146.08). The absence of a significant leak can be evaluated using either monitoring of annulus pressure, pressure testing with liquid or gas or, in specified instances, monitoring records that show no significant change in the relationship between injection pressure and injection flow rate. The absence of significant fluid movement can be evaluated by using the results of a temperature or noise log, or, for Class II wells, by presenting well records that demonstrate the presence of adequate cement to prevent migration (146.08). A definition of the term "significant" was not included in the regulations. A qualitative definition provided by Webster (Guralnik, 1976) states that "significant" means "of or pertaining to an observed departure from a hypothesis too large to be reasonably attributed to chance". While the intent of the regulations is thus clarified, question as to a quantitative value for each test has been raised. While this question is a valid concern, it is not the purpose of this report to provide an interpretation of the federal regulations. Additional regulations which are specifically applicable to Class II wells (CFR 40, Part 146.08 and Part 146 Subpart C) are further detailed.

The permitting authority in each state with a UIC program in force or the appropriate regional EPA administrator is charged with authorizing the construction of a proposed injection well and overseeing the continued operation of existing injection wells. Prior to granting approval for the operation of the injection well, the permitting authority must evaluate the mechanical integrity of the injection well. To assist the permitting authority, the permit applicant must submit (along with other specified information) a demonstration of mechanical integrity of the injection well which is in accordance with the methods described in the preceeding paragraph (146.24). However, the rules do allow the applicant to petition for acceptance of additional methods for determining the mechanical integrity of the injection well. The EPA Administrator has the authority to evaluate additional methods and grant approval for their use (146.08).

Once a permit granting approval for operation has been issued, operating, monitoring and reporting requirements must be followed by the operator of the injection well (146.23). Of particular importance are the requirements that: 1) observation of the flow rate, injection pressure and cumulative volume be conducted at specified time intervals, 2) a demonstration of the mechanical integrity be provided at least once every five years during the life of the injection well, and 3) the results of all monitoring be maintained until the next permit review as determined under 40 CFR 122.42 (e) (146.23). These provisions help to guarantee that the mechanical integrity of the well is present initially and also maintained throughout the life of the injection well. This helps to ensure that injection will not result in the migration of fluids into an underground source of drinking water so as to create a significant risk to the health of the persons using the source of drinking water.

PROBLEM ASSESSED

Ground water and surface water contamination instances from oil field brine disposal practices, especially surface discharges and unlined pits, are well documented in the literature (Fryberger, 1972; Oklahoma Water Resources Board, 1975; Pettyjohn, 1971; Payne, 1966). As a result, present disposal operations are typically limited either to underground injection or to discharge into lined lagoons. It is estimated that there are approximately 140,000 Class II wells in use across the United States.

With the increasing emphasis on brine injection operations, the UIC regulations were adopted, in part, to help reduce the potential for the contamination of underground sources of drinking water by Class II injection wells (Federal Register, 1980). In general, two types of injection wells are utilized in oil and gas production operations: 1) brine disposal wells in which the fluid is injected into a receiving formation for the purpose of retention; and 2) enhanced recovery wells in which the fluid is injected into a producing formation for the purpose of increasing the production of oil and gas. Both types of wells are virtually identical in design, construction materials and completion, and can be completed as new wells or converted from existing production wells.

Injection wells can be operated without endangering ground water provided they are properly constructed and maintained in such a way as to ensure their mechanical integrity. Saltwater injected under pressure or by gravity into wells may escape through leaks in the well casing caused by a mechanical failure within the well, or through migration of brine forced up between the well's outer casing and the wellbore because of a faulty cementing job (Figure 1). Determination of the mechanical integrity of an injection well is extremely important, since it provides a measure of the protection of fresh water aquifers from contamination.

ORGANIZATION

This document contains 18 sections and 2 supporting appendices. The development of the sections and appendices are user-oriented. Section 4 provides a basic introduction to the design of injection wells. Sections 5 and 6 address methods of determining the mechanical integrity of injection wells which do not require the services of a professional well logging company or specialized contractor. Section 7 provides an introduction to well logging and to services performed by well logging companies. Sections 8 - 17 address different logging techniques which may help determine mechanical integrity of injection wells. Section 18 describes other methods which may also have application. An attempt has been made to summarize applicable techniques and technologies throughout the report. Each section contains a reference section for additional information.

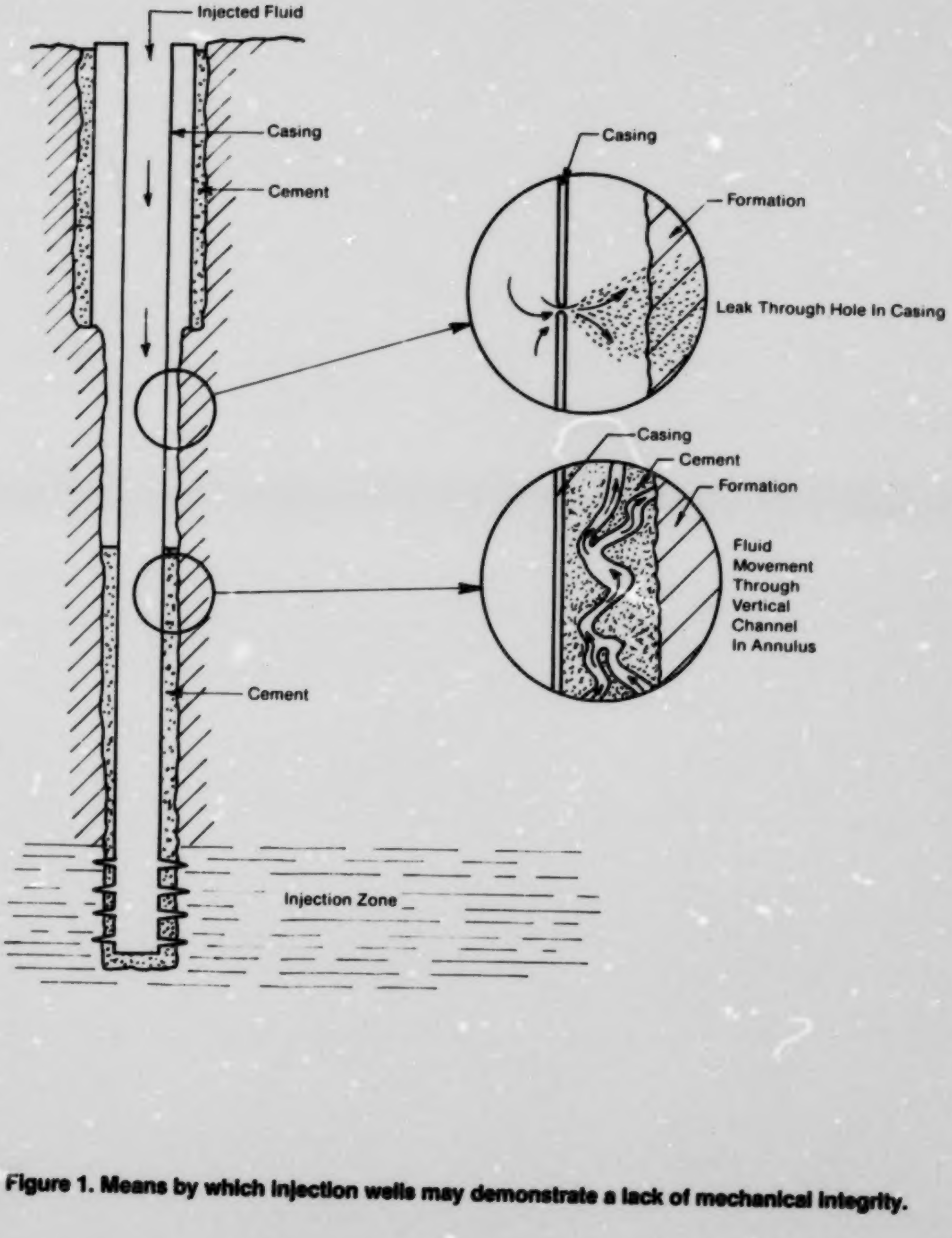

Figure 1. Means by which injection wells may demonstrate a lack of mechanical integrity.

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SECTION 2

CONCLUSIONS

Leaking injection wells may result in the migration of fluids into an underground source of drinking water so as to create a significant risk to the persons using that source of drinking water. However, injection wells can be operated without endangering ground water provided they are properly constructed and maintained in such a way as to ensure their mechanical integrity.

All Class II injection wells must demonstrate that there is no significant leak in the casing, tubing or packer and that there is not significant fluid movement through channels adjacent to the injection well to ensure mechanical integrity. To date, the UIC program requires that the absence of a significant leak in the casing, tubing or packer be evaluated using either monitoring of annulus pressure, pressure testing with liquid or gas or, in specified instances, monitoring records that show no significant change in the relationship between injection pressure and injection flow rate. The absence of significant fluid movement can be evaluated by using the results of a temperature or noise log, or, for Class II wells, by presenting well records that demonstrate the presence of adequate cement to prevent migration.

In addition to these methods, there are a number of other methods which are not currently approved for use which may also be used to determine the mechanical integrity of injection wells. Pipe Analysis Surveys, Electromagnetic Thickness Surveys, Caliper Logging, Flowmeter Surveys, Radioactive Tracer Surveys and Cement Bond Logs which are available from professional well logging companies are capable of detecting leaks in the casing, tubing or packer and/or fluid movement behind casing. Borehole Television and Borehole Televiewer surveys, which are performed by specialized contractors, may also be used to detect leaks. Table 1 provides a detailed listing of the detection capabilities, well diameter constraints and pressure/temperature limitations of each of these techniques as well as the techniques approved for use in the UIC program.

Nearly all of the testing methods currently available are available only through professional well logging companies which specialize in these and other injection well and production well services. Many of these companies have district or regional offices

TABLE 1. SUMMARY OF APPLICATIONS OF METHODS WHICH MAY BE USED TO DETERMINE THE MECHANICAL INTEGRITY OF CLASS II INJECTION WELLS

	Detection Capability		Well Diameter Constraints		For Use in Casing or Tubing	Pressure/Temperature Limitations of Technique
	Leaks in Casing, Tubing or Packer	Fluid Movement Behind Casing	Minimum	Maximum		
Monitoring Annulus Pressure	X		N/A	N/A	**	N/A
Pressure Testing	X		N/A	N/A	both	N/A
Temperature Logging						
(Gradient)	X	X	1½"	8½"	both	20,000 psi/400° F
(Differential)	X	X	1½"	8½"	both	20,000 psi/400° F
(Radial Differential)	X	X	2⅜"	13⅜"	both	20,000 psi/400° F
Noise Logging	X	X	1½"	no limit	both	15,000 to 22,000 psi/350° F
Pipe Analysis Survey	X		4½"	9⅝"	casing	10,000 psi/250° F
Electromagnetic Thickness Survey	X		4½"	9⅝"	casing	20,000 psi/350° F
Mechanical Caliper Logging	X		2"	13⅜"	both	10,000 psi/300° F
Borehole Television	X		3"	36"	casing	5,000 psi/175° F
Borehole Televiewer	X		2⅜"	8½"	casing	15,000 psi/175° F
Flowmeter Surveys	X		2"	10"	both	varies widely according to tool design
Radioactive Tracer Surveys	X	X	1½"	no limit	both	15,000 psi/300° F+
Cement Bond Logging		*	2"	no limit	casing	20,000 psi/400° F

* inferred only
** annulus between casing and tubing
N/A not applicable
+ depends on choice of gamma ray detector

across the country, thus most services are readily available in most areas. In addition, many of the methods described in detail in this document have been utilized, in one form or another, by the petroleum industry for a number of years. Therefore, these methods have been tested not only under laboratory conditions, but also under field conditions, and the interpretation of results is fairly well established.

Since many different tests may be applicable for determining the mechanical integrity of Class II injection wells, the advantages and disadvantages of each method must be understood to facilitate a rational decision regarding which method or methods can be applied in each individual situation. Few of the methods which can be employed to test the mechanical integrity of injection wells can be used alone to provide definitive information on both the presence and the location of leaks in the casing, tubing, or packer, and fluid movement behind the casing. In general, it will take two or more testing techniques, run either independently or in conjunction, to ensure that no significant leaks exist in the casing and that no fluid movement is occurring in the cement sheath behind the casing. Table 2 provides a detailed summary of the advantages and disadvantages of all methods which may be used to determine the mechanical integrity of Class II injection wells. When used in conjunction with Table 1 which lists the applications and limitations of all the methods, the best method or combination of methods may be chosen.

TABLE 2. SUMMARY OF ADVANTAGES AND DISADVANTAGES OF METHODS THAT MAY BE USED TO DETERMINE THE MECHANICAL INTEGRITY OF CLASS II INJECTION WELLS

Method	Advantages	Disadvantages
Monitoring Annulus Pressure	Provides "real time" measurement Well does not have to be taken out of service No specialized equipment needed Very inexpensive Provides either continuous or frequent, regular measurement	Injected fluid temperature and pressure changes complicate interpretation Provides no information on leak location Limited to use in wells completed with tubing and packer
Pressure Testing	Most tests of short duration Minimum of specialized equipment needed Relatively inexpensive for most wells Results straightforward and easy to interpret Staged tests provide information on leak location	Some disruption of service Non-staged tests provide no information on leak location Application of excessive pressures could damage well
Temperature Logging	Can detect and locate both leaks in casing, tubing or packer and fluid movement in channels behind casing Gradient and differential logs available from most logging companies	Requires professional service, equipment and interpretation Requires removal of well from service for extended period (24 to 48 hours or more) Use limited in large-diameter wells Radial differential log available from only one logging company
Noise Logging	Can detect and locate both leaks in casing, tubing or packer and fluid movement behind casing Possible to distinguish between single and dual phase flow Possible to estimate rate and volume of flow from a source Available from most major logging companies	Requires professional service, equipment and interpretation May require removal of well from service for extended period Injection operations must be stopped during logging May not be useful for detecting flow behind casing when pressure differentials too low

TABLE 2 (continued)

Pipe Analysis Survey	Developed specifically to evaluate downhole casing damage Can distinguish between internal and external casing damage Can detect and locate small defects (1/8-inch diameter) in casing	Offered only by a select few well logging companies If tubing removal necessary, requires removal of well from service for extended period
Electromagnetic Thickness Survey	Offers only method of detecting defects on the outer string of double casing string	Cannot detect small casing defects (less than 1-inch diameter) If tubing removal necessary, requires removal of well from service for extended period Difficult to distinguish true cause of log anomalies Requires availability of baseline log against which comparison is made to subsequent logs Offered only by a select few well logging companies
Mechanical Caliper Logging	High resolution caliper provides very accurate record of condition of casing interior Log can be run in short amount of time Log can be run in either tubing or casing	May not detect small-diameter (1/2-inch) defects Difficult to locate vertical splits or cracks in casing High resolution caliper offered only by a select few well logging companies
Borehole Television	Provides for direct visual inspection of downhole conditions Video tape recording provides for ease of replay and comparison with other logs	Well fluid must be free of suspended material If tubing present, must be removed Operation requires removal of well from service for extended period Service not offered by commercial well logging companies; specialized contractor necessary Cannot be run in high temperature/pressure environments

TABLE 2 (continued)

Borehole Televiewer	Provides easily recognizable image of casing interior Provides either photographic or videotape record Limited interpretation necessary Can operate in less favorable environments than borehole television	If tubing present, must be removed Operation requires removal of well from service for extended period Technique relatively slow Service not offered by commercial well logging companies; specialized contractor necessary
Flowmeter Surveys	Log can be run in either tubing or casing Possible to estimate volume of flow from leak Log run during injection; little disruption of service Available from most major logging companies	Flow rates must be high enough for flowmeter to function Injection rate must be held constant for proper interpretation Requires professional service, equipment and interpretation
Radioactive Tracer Surveys	Log can be run in either tubing or casing Log run during injection; little disruption of service Available from most major logging companies	Requires use of radioactive tracer Requires professional service, equipment and interpretation
Cement Bond Logging	Infers presence of channels behind casing Available from most major logging companies	If tubing present, must be removed Cannot be used to find leaks or determine fluid movement Many factors affect log validity Requires professional service, equipment and interpretation Interpretation complicated and not standardized within industry

SECTION 3

RECOMMENDATIONS

There are many methods which may be applicable for determining the mechanical integrity of Class II injection wells. Because of the many variations in injection well completions, it is not possible to make recommendations regarding mechanical integrity testing methods which apply to all such wells. Since each well is unique, testing procedures should be carefully selected and tailored to the individual well. The following list of criteria should be used to help establish a systematic approach to choosing the appropriate testing methods:

1) Determine the type of completion of the well;

2) In wells completed with tubing and packer, determine the type of packer to evaluate the maximum amount of pressure which can be applied to the annulus between the tubing and casing;

3) Determine the inside diameter of the casing or tubing to assess tool diameter limitations;

4) Determine the depth of the well to evaluate pressure/temperature limitations of methods;

5) Determine the wall thickness of casing or tubing since selected methods rely on the measurement of thickness to determine the soundness of the pipe;

6) Attempt to determine the interval(s) of injection to facilitate the application or interpretation of tests;

7) Evaluate the availability of professional companies to perform the service, if applicable;

8) Evaluate the cost of the method with respect to the type of results desired.

Because some of the testing methods detailed in the "Other Mechanical Integrity Testing Methods" Section of this report have not been specifically used or properly evaluated for use in testing the mechanical integrity of Class II injection wells, further study is needed in the following areas:

1) Gamma ray logging has traditionally been used in injection wells for purposes other than leak detection, however further study into the applicability for leak detection is needed;

2) Helium leak testing has been used to test for leaks in other applications, but has not been applied specifically to injection wells. This method should be laboratory and field tested to determine its applicability to injection wells;

3) Volumetric scanning has been used for fracture evaluation in open boreholes, but further evaluation for use in cased hole applications is necessary; and

4) Continuous oxygen activation logging has been field tested for application of determining leaks in injection wells but the results are inconclusive. Further testing is needed to assess the applicability of this technique.

SECTION 4

BASIC INJECTION WELL DESIGN

INTRODUCTION

It is presumed that most readers of this document have a basic knowledge of injection well design. However, for the purpose of standardizing the terms used in subsequent chapters, it is appropriate to review the basic design of the types of wells (Class II) that this document deals with. This chapter is not intended to be a detailed discussion of injection well design, as numerous examples of this appear in the literature.

The common objective for Class II injection wells, both brine disposal and enhanced recovery wells, is to furnish a pathway for the subsurface emplacement of fluid without endangering fresh-water aquifers. Because of this common objective, the design and construction details and the operational practices employed in both types of wells are very similar.

Injection wells can be classified into three general types based on the method of completion (American Petroleum Institute, 1978): 1) cased-hole completions, in which the well is cased and cemented through the injection zone then opened through perforations (Figure 2A); 2) open-hole completions, in which the well is cased and cemented to the top of the injection zone and the well advanced into the formation intended for injection (Figure 2B); and 3) liner completions, in which the well is cased and cemented to a shallower formation, drilled deeper, and a liner set through the injection zone, cemented, and opened through perforations (Figure 2C).

Many variations in these three methods of completion are found, particularly in wells which were originally completed as production wells and then converted to injection wells. Construction details in these wells are dependent on practices in use at the time of completion and on local conditions. One variation which is common in some parts of the country is the tubingless or "slim-hole" completion, in which the tubing is cemented in a small borehole to serve as both the long string and the tubing string. These and other so-called "non-standard" completions pose the most difficult problems to regulators because the wells do not conform to UIC standards.

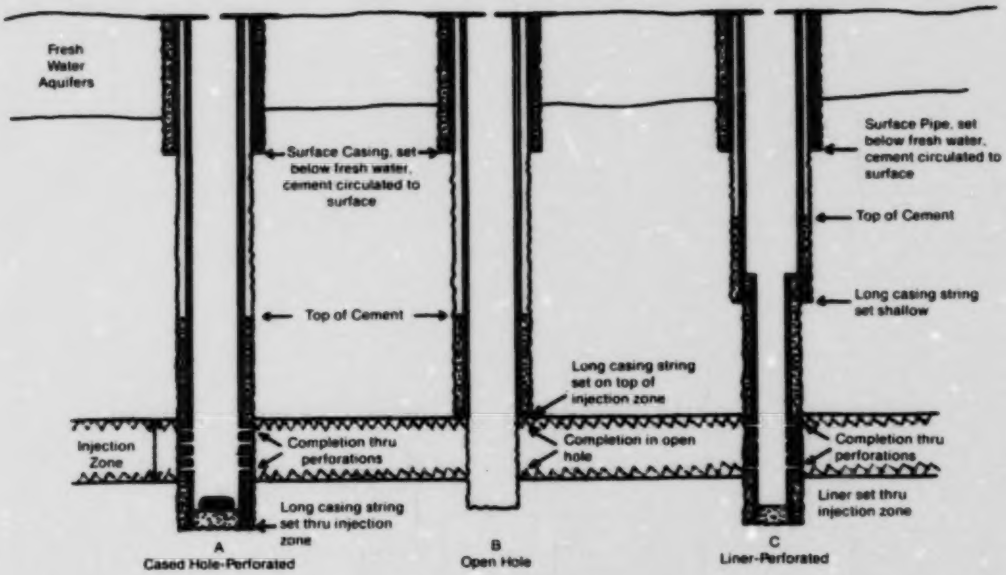
Fresh
Water
Aquifers
Surface Casing, set below fresh water, cement circulated to surface
Top of Cement
Injection Zone
Completion thru perforations
Long casing string set thru injection zone
A
Cased Hole-Perforated
Long casing string set on top of injection zone
Completion in open hole
B
Open Hole
Surface Pipe, set below fresh water, cement circulated to surface
Top of Cement
Long casing string set shallow
Completion thru perforations
Liner set thru injection zone
C
Liner-Perforated

Figure 2. Common methods of class II injection well completion (After American Petroleum Institute, 1978).

For the purposes of this document, it is assumed that most so-called "standard" operational Class II injection wells are composed of several basic design elements. These elements, as illustrated in Figure 3, include: casing, cement, injection tubing, packer, and the wellhead.

CASING

The primary functions of casing are to prevent the borehole from caving, to confine the injected fluid to the well bore and the intended injection zone (to prevent contamination of fresh-water aquifers), and to provide a method of pressure control. Design of a casing program depends primarily on well depth, character of the rock sequence, fluid pressures, type of well completion, the corrosiveness of the fluids that will contact the casing and the water quality of the aquifers through which the casing is installed.

Three different "strings" or types of casing may be used in injection wells: a surface string, an intermediate string, and a long string (or injection string). The number of casing strings and their setting points are generally governed by geologic conditions. There are normally at least two casing strings as illustrated in Figure 3; the surface string and the long string. An intermediate string of casing may be used in deeper completions, but is not always necessary. A liner may also be used in deeper completions, for reasons of economics.

In most recently completed injection wells, surface casing is installed through the deepest fresh-water aquifer and is seated into a confining layer beneath the aquifer. Cement is then circulated back to the surface in the annulus between the casing and the borehole. The surface casing then protects fresh-water aquifers from foreign fluids during the drilling operation, continues to offer this protection during the life of the well, and will be left in place with cement both inside the casing and between casing and borehole upon abandonment of the well. Older existing production wells which have been converted to injection wells may not have the surface string cemented to the surface.

Within the surface string is installed the long casing string, or the injection string, which is the permanent connection between the surface and the injection zone. The diameter of the casing used in the long string is selected based on the following considerations (Warner and Lehr, 1977):

1. Tubing diameter. The inside diameter of the casing must be great enough to accommodate the packer and tubing (coupling diameter).

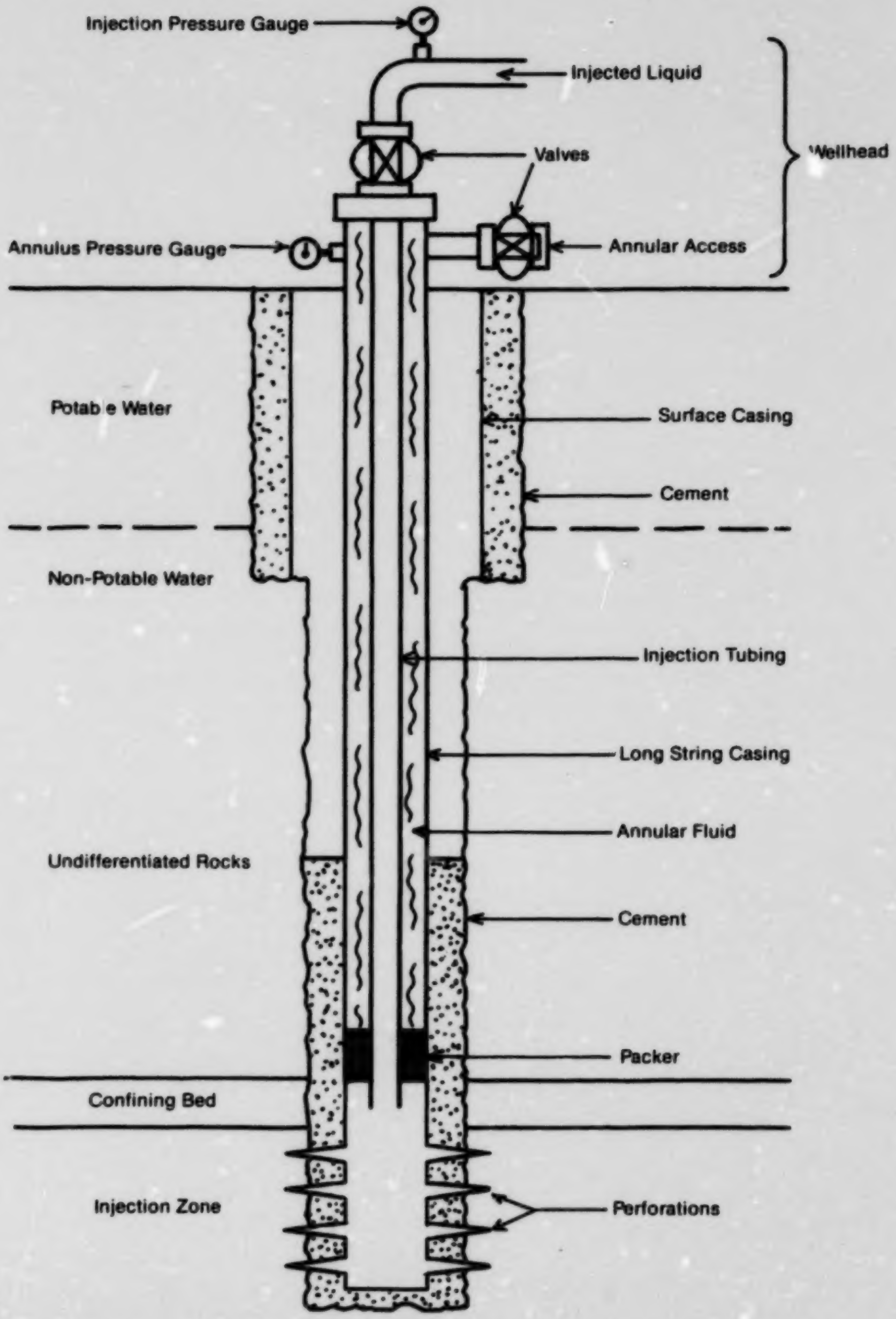

Figure 3. Basic design elements of a typical class II injection well.

2. Cost of drilling and casing. Since the cost of drilling and casing increases with hole diameter, the size should be minimized.

3. Workovers. Since remedial work is frequently necessary in injection wells, the casing size must accommodate workover equipment. During their lifetimes, many injection wells require some form of maintenance ("workover" in the terminology of the petroleum industry). Workovers are commonly attempted for the following purposes:

a. Well repair

1) Replace damaged tubing and/or packers
2) Repair damaged or corroded casing
3) Perform remedial well cementing
4) Install additional liners or casing

b. Maintenance of injection capacity

1) Reperforating
2) Acidizing
3) Fracturing
4) Mechanical or hydraulic cleaning of the wellbore

c. Recompleting or deepening to a new injection interval

4. Common practice. The experience of others in the geologic area of interest and in similar operating situations should guide the final choice.

The decision on the size of the casing used in the long string fixes the minimum size of the hole and of all other casing strings. The hole diameter is nearly always at least two inches greater than the casing coupling outside diameter to allow at least a one-inch sheath of cement around the casing (American Petroleum Institute, 1978).

Depending on the type of completion, the long string is installed either to the top of the injection zone (open-hole completion), through the injection zone (cased-hole completion) or to some point above the injection zone (liner completion). It is designed with adequate tension, burst and collapse strength to withstand formation pressures, injection pressures, and cementing. Because of these constraints, the long string is nearly always steel casing.

A long string, properly designed, set, and cemented, allows no movement of injected fluids up the annulus. During the operation life of the well, specific attention should be directed to the protection of the injection string from abuse and corrosive fluids because this casing is the permanent avenue of access from the surface to the injection zone.

A liner may be utilized where economics or site conditions dictate. Like the long casing string, the liner is the means of accessing the injection zone. Thus, the liner is designed for burst, collapse and tension just as the long string, and is cemented to impede movement of injected fluids up the annulus, though achieving a competent completion is more difficult to obtain with a liner than with the long string (American Petroleum Institute, 1978).

CEMENTING

Cementing of injection wells entails mixing a slurry of cement and water and pumping it down, usually through casing, into the open hole below the casing. The cement is then forced upward, under pressure, into the annulus between the casing and the borehole or between the casing and previously installed larger casing. Although cement is normally emplaced through the casing, other methods of emplacement are available for special situations.

The principal functions of cementing are to forestall travel of injected fluids into formations other than the injection zone, to restrict fluid movement between formations and to bond and support the casing. Cement also aids in protecting the casing from external corrosion and in isolating high pressure or lost circulation zones. Another type of cementing procedure, squeeze cementing, is used to correct defective primary cementing jobs. In squeeze cementing, cement is selectively placed to fill intervals not completely cemented during primary cementing. Squeeze cementing can also be used for other purposes, such as selective plugging of an injection interval without abandonment of the entire well.

In the installation of surface casing, cement should always be circulated back to the surface, thus ensuring that the aquifers through which the surface casing is installed are protected. In installing the long string, circulation of cement back to the surface is desirable, but in deep completions, is not always economically feasible or mechanically possible. In some cases, regulatory authorities may allow a well to be constructed with only the bottom of the long string cemented to a specified level above the injection zone. In other cases, cementing the upper portion of casing by circulating through a multiple-stage cementing tool installed in the casing below the base of fresh water, may be required. In deep wells, multiple-stage cementing of the long string casing is usually necessary to reduce the risk of lost circulation and to allow for better cement bonding between the casing and the formations.

A successful primary cementing job is considered to be as important as any aspect of injection well construction. Even the best-designed well can be rendered inadequate if the casing is not adequately bonded to the formations above the injection zone. A poor cement job can allow vertical migration of injected fluids in channels between injection casing and the borehole. In some cases, fresh water aquifers could be endangered, but perhaps a greater danger is from external corrosion of the longstring casing that can lead to loss of the well.

In new injection well completions, the primary cement job should always be checked. Commonly used methods of checking cement include temperature surveys, cement bond logs, and noise logs. Temperature surveys and radioactive tracer surveys are used for locating the top of cement behind casing. Cement bond logs are used to indicate the quality of the bond between the cement and the casing and the bond between the cement and the formation. Noise logs and radioactive tracer surveys can be used to determine the presence of channels in the cement. These and other logs are discussed further in subsequent chapters.

In open-hole completions, after the injection string is set at the top of the injection zone and cemented, the cement at the bottom of the well is drilled out and the well is completed. In cased-hole completions, access to the injection zone is usually obtained after the well has been cased and cemented, through perforations in the casing string. The casing may be perforated by any one of several means, but is usually perforated by shaped-charge jets.

INJECTION TUBING

Most recently installed wells injecting potentially corrosive fluids have been constructed with injection tubing inside the long casing string, and with a packer set between the tubing and the casing near the bottom of the well. The tubing is the controlling element of injection well construction because it conveys the fluid to the injection zone.

Tubing size is based on the volume of fluid to be injected, but there is no fixed relation between the two. For a specified fluid volume, an increased tubing size requires less energy to force the fluid through the tubing, but increases tubing cost. The optimum tubing size is that which minimizes the cost of operation and still meets the engineering requirements of the system. Tubing grade and weight are selected in a manner similar to that for selecting casing grade and weight. However, because of the relatively small diameter of tubing, more pressure is required to inject fluids at high rates through tubing than through casing. Thus, selection of proper tubing grade and weight must reflect this consideration.

Tubing for injection wells is available in various types and grades of steel and other materials. The material used for tubing in Class II wells is generally steel, but when the injected fluid, usually saltwater, is corrosive, the steel tubing is protected from internal corrosion by plastic coating. Unlined steel tubing may be utilized in the well if the injected fluid has been treated with a corrosion inhibitor or is not corrosive.

Protection from corrosion can also be obtained by substituting non-corroding materials, such as fiberglass, for the standard steel normally used. However, because fiberglass is not as strong as standard steel, it is only useful in wells where high injection pressures are not anticipated and in those installations where well depths are compatible with the tensile properties of the material.

PACKERS

Packers are designed to seal off, or "pack off" certain sections in an injection well. They may be used to protect casing from injection and formation pressure and fluids, to isolate given injection zones, and as a subsurface safety control. Packers can also be used to isolate specific zones within a well to allow for multiple completions in the same well bore.

Most packers used in injection wells are of three basic types - those in which the tubing is positioned in tension (tension-set), those in which the tubing is held in compression (compression-set), and universal packers. These packers are all seated by movement of the tubing. This may be accomplished by use of the tubing weight as in the case of a compression-set packer; this type of packer may be retrieved by simply lifting up on the tubing. Tension-set packers are set by a pulling tension on the tubing; they are released by slacking off on the tubing. Tension-set packers are set even tighter by pressure from below and therefore work well in some injection wells. Compression-type packers are generally less expensive than tension-type packers because they are less complex mechanically. Universal packers are generally preferable if the fluid being injected is warm to hot. With some of these packers, a long seal assembly can be used, allowing the lower end of the tubing to move freely in response to thermal expansion without destroying the integrity of the seal. If the fluid being injected is relatively cool, then thermal expansion is not a consideration and the tubing can be set in compression if high pressures are not anticipated.

Other types of packers which may find use in injection wells include rotational-set packers and hydraulic packers. Rotational-set packers are set using a left-hand rotation to extend the slips; this procedure is reversed to release the packer. The primary advantage of rotational packers in injection wells is that the tubing may be set in a neutral-weight situation, thus eliminating the possibility of unseating the packer due to tubing elongation (as when using a tension-set packer) or separating due to contraction (as when using a compression-set packer.) The main disadvantage of rotational-set packers is that solids tend to settle out on top of the packer which prevents any rotational action; thus, on attempting to release the packer, the tubing may unscrew (Warner and Lehr, 1977).

The hydraulic-set packer employs fluid pressure to wedge the slips; once set, this type of packer is usually held by a mechanical lock. Retrieval is by either rotation or tension. Hydraulic-set packers are used particularly where tubing movement is limited. This type of packer also allows the tubing to be in a neutral-weight state.

A special type of hydraulic packer is the inflatable or "balloon" packer which can be used in either open holes or cased wells. The packer element is set by applying fluid pressure. Primary usage occurs in wells with partially collapsed casing. Inflatable packers will not withstand high pressure differentials, and are relatively expensive, thus they are not widely used in injection wells.

In some situations, it is possible to complete a well using tubing without using a packer. This technique, referred to as the hydraulic seal technique, is one in which a hydraulic barrier rather than a mechanical one is used to prevent the migration of injected or formation fluid up the casing-tubing annulus. This type of seal can be used only in cases in which the hydrostatic pressure of the formation is sufficient to raise the formation fluid to some level up inside the well. The seal is made by pumping fresh water or a light oil, such as kerosene or diesel oil, into the annulus and displacing the formation water downward to a point near the bottom of the well. The annulus is then closed off at the surface and a valve and pressure gauge installed at the wellhead to monitor the annulus pressure. Because the oil is for all practical purposes incompressible, any variations in injection pressure are reflected in the annulus pressure. If any changes in the annulus pressure are noted while injection pressure remains constant, or if the differential pressure is found to decrease or increase, this is an indication of a leak in either the casing or the tubing.

ANNULAR CORROSION PROTECTION

The annular space between the tubing and the casing should always be filled with a corrosion-inhibiting fluid to protect both the tubing and casing from the effects of corrosion. Fresh water treated with a chemical inhibitor is widely used for this purpose, but other fluids, including light oils, may also be used. Regulatory authorities may require that a positive differential pressure be maintained on the annulus fluid so that well malfunctions may be detected.

WELLHEAD

The final components of the injection well are the wellhead and appurtenant structures, which are all standard oil-field equipment. The wellhead is the main link between the surface fluid distribution system and the downhole equipment, and generally consists of a surface casing flange, casing hanger and spool and tubing flange. Where metering is required, as in most larger operations, or where other equipment (i.e. valving, pressure taps, etc.) is desired, the wellhead may be more complex. Pressure gauges are generally installed on the injection tubing and on the tubing-casing annulus (if one exists) at the wellhead. Continuous recording devices may be installed to record injection tubing pressures and injection flow rates and volumes. An automatic alarm or shut-down system may be installed to signal the failure of any important component of the injection system, or to shut off the system should a failure occur.

CONSIDERATIONS IN MECHANICAL INTEGRITY TESTING

Before any type of mechanical integrity testing can be performed on an injection well, the following details of well completion must be known about the well:

1) The type of completion must be determined. Testing procedures which may work well in, for example, a well without tubing and packer, may not work at all in a well completed with tubing and packer.

2) The depth of the well should be known, as some testing methods have limitations with regard to the depth at which they perform well.

3) The interval (or intervals in the case of multiple completions) into which injection is taking place, should be identified so that testing can avoid it (or them) or so that it (or they) can be accounted for in the interpretation of test results.

4) The inside diameter of the casing and the tubing is also critical, as some methods require the use of downhole tools, the diameter of which may preclude their use in some wells.

5) Casing and tubing wall thickness should also be determined before any mechanical integrity testing is done, as some methods of testing rely on measuring that thickness as a means of determining the soundness of the pipe.

6) In wells completed with tubing and packer, the type of packer used in the well must be known, primarily for pressure testing. The type of packer will determine the maximum amount of pressure which can be applied to the annulus between the tubing and casing.

Many variances in methods of completion of injection wells are encountered, particularly in older existing wells where factors at the time the wells were completed influenced construction practices. Also, wells with extensive downhole repairs may have unusual mechanical configurations. In view of the great variety of types of completions of injection wells, and the complications involved in mechanical integrity determinations, it is critical to realize that it is not possible to make general statements about mechanical integrity testing of injection wells. Each well is unique with respect to its individual characteristics, and testing procedures should be carefully selected and tailored to the well to ensure that testing can be performed in the most efficient, cost-effective manner.

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Warner, D.L. and J.H. Lehr, 1977, An introduction to the technology of subsurface wastewater injection; U.S. Environmental Protection Agency publication #EPA-600/2-77-240, 345 pp.

SECTION 5

MONITORING OF ANNULUS PRESSURE

SYNOPSIS

Many injection well operators utilizing wells completed with tubing and packer routinely measure and keep a record of the pressure on the corrosion-inhibiting fluid in the annulus between the casing and the tubing. The practice of monitoring annulus pressure is employed to detect any changes in pressure which may indicate leakage through the injection tubing, the casing or the tubing-casing packer.

Because annulus pressure is normally monitored on either a continuous or frequent, regular basis, this method provides for determination of a mechanical integrity problem relatively soon after it occurs. Other testing methods, which are normally employed only periodically (federal and some state regulations require mechanical integrity testing only once every five years), may only detect a leak years after it has occurred. The cost of annulus pressure monitoring is very low, and equipment requirements are minimal. Monitoring of annulus pressure can be conducted without removing the well from service.

A potential problem in utilizing annulus pressure monitoring as a means of determining injection well mechanical integrity is that interpretation of test results may be complicated by changes in injection pressure and injected fluid temperature.

PRINCIPLES

The principle of annulus pressure monitoring is very simple. The annular space in an injection well which is closed at the bottom with a packer and at the top with a wellhead functions as an enclosed vessel. If the fluid in an enclosed vessel is maintained at a fixed volume and temperature the fluid pressure should remain constant if there is no leak. Pressure changes within the vessel can be caused by indirect outside influences (i.e. outside pressure or temperature acting on the vessel and thus the fluid inside) or by direct communication between the inside of the vessel and the outside environment. Thus, the vessel (or annulus) will experience pressure changes whenever the outside influences are great enough or whenever an avenue of direct communication (a leak) exists.

EQUIPMENT

The only equipment necessary to conduct annulus pressure monitoring is a standard wellhead pressure gauge which is normally installed upon completion of a tubing and packer well. If no operable, accurate pressure gauge is present on the annulus, an appropriate fitting should be provided so that a gauge can be temporarily installed to take pressure readings. This equipment is inexpensive and readily available.

PROCEDURES

Two conditions commonly exist in injection wells: 1) where the casing-tubing annulus is not pressurized at the surface and the initial pressure is atmospheric except for some pressure resulting from the expansion of the injection tubing (Warner, 1975) and 2) where positive pressure of a predetermined amount is maintained on the casing-tubing annulus. Dimatteo (personal communication, 1983) suggests that pressure on the annulus be maintained at 10 psi above atmospheric pressure; this is to ensure that a positive pressure will always be exerted on the pressure gauge regardless of changes in the annulus pressure during injection. Owens (1975) suggests that a pressure greater than that of the injection pressure be maintained on the annulus. With the latter arrangement, any leakage in the tubing creates leakage into the injected fluid stream and thus a detectable drop in annulus pressure. This procedure may be limited to use in relatively new wells where the injection string is designed to withstand such pressure. In older wells or in wells converted from producing wells where casing is not designed to withstand such pressures, this procedure is not advisable.

Monitoring of annulus pressure can be conducted either continuously or on a periodic basis. Continuous monitoring is accomplished by utilizing a recording device which plots annulus pressure versus time. The monitoring device is usually checked by the operator on a regular basis (i.e. daily, weekly or monthly). Some continuous monitoring systems are connected to an alarm or shut-down device so that when the annulus pressure drops below or exceeds a predetermined amount, an alarm warns of failure and the injection operation shuts down until the cause of failure is located.

Periodic monitoring is accomplished by the operator noting the pressure displayed on the wellhead pressure gauges on a regular basis. Common industry practice is to monitor annulus pressure on either a weekly basis or a daily basis; in some cases, daily monitoring may be required. Table 3 illustrates annulus pressure monitoring requirements of eleven states which have set these requirements. Requirements range from daily monitoring/weekly reporting to quarterly monitoring/annual reporting.

TABLE 3. ANNULUS PRESSURE MONITORING REQUIREMENTS OF SELECTED STATES

State	Frequency of Monitoring Required	Frequency of Reporting Required
Alabama	Weekly	Bimonthly
Colorado	Weekly	Monthly
Florida	Daily	Weekly
Louisiana	Daily	Monthly
Michigan	Quarterly	Annually
Nebraska	Weekly	Monthly
New Mexico	Monthly	Annually
Ohio	Monthly	Quarterly
Oklahoma	Monthly	Annually
Texas	Monthly	Annually
Wyoming	Daily	Monthly

Annulus pressure is generally recorded on a standard form so that readings taken at different times may be compared in a similar format. Injection pressure and temperature of the injected fluid should also be recorded to provide a better basis for interpretation of the annulus pressure monitoring data.

INTERPRETATION

Interpretation of annulus pressure monitoring results, under conditions where there are no changes in either injection pressure or injected fluid temperature, is relatively straightforward. In an operating injection well in which there is no surface pressure maintained on the casing-tubing annulus, a leak in the tubing or packer will cause pressure in the annulus to increase if there is fluid entry from the tubing or the injection formation. The pressure will decrease if the hydrostatic pressure on the annulus fluid is greater than the injection pressure or the pressure in the injection formation. A leak in the casing may manifest itself as either an increase or decrease in the annulus pressure, depending on whether the pressure outside the casing is greater than or less than hydrostatic pressure on the annulus.

In a well in which some pressure is maintained on the annulus fluid, the response of annulus pressure will depend on the amount of pressure applied at the surface and on the pressure differential between annulus pressure and the pressure at the source of the leak. If annulus pressure is greater than injection pressure, and a leak occurs in the tubing or packer, a pressure drop in the annulus will occur. Likewise, if annulus pressure is greater than formation pressures and a leak occurs in the casing, annulus pressure will drop. The reverse is true for tubing or packer leaks if injection pressure exceeds annulus pressure, and for casing leaks if formation pressure exceeds annulus pressure.

In wells in which a pressure drop is noted on the casing-tubing annulus, it is possible to relate the pressure decrease to volume of fluid lost. Langlinais (1981) provides tables which can be used to estimate the volume of fluid lost from a well for a given annulus pressure change (Appendix A). As an example, he suggests that a well with a 7 5/8" diameter casing and a 2 3/8" diameter tubing, with a packer at 3000 feet, would experience a loss of 1.929 gallons of annulus fluid with a 100 psi pressure drop in the annulus. The flow rate depends on the time period over which the pressure drop is noted. Thus, if the 100 psi pressure drop had occurred for a 15 minute period, the fluid loss rate from the well would be 185 gallons per day. This would apply to a leak in either the casing, the tubing or the packer.

In practice, several variables may complicate the interpretation of annulus pressure monitoring results. The two major phenomena that affect monitoring of annulus pressure are the responses of the annulus to injection pressure changes and to injected fluid temperature changes.

An injection well with a closed annulus will experience annulus pressure changes whenever injection pressures are changed because the mechanical dimensions of the tubing change with injection pressure; thus, the volume of the annulus and hence the annulus fluid pressure at the surface will vary. Langlinais (1981) determined that annulus pressure responses are sensitive to the following variables: 1) changes in injection pressure; 2) the well geometry (relative sizes of tubing and casing); and 3) the permeability of the injection zone multiplied by the thickness of the injection zone (in darcy-feet). He was able to establish a relationship in annulus pressure change to injection pressure change for a given well geometry and injection zone permeability x thickness (Table 4). Using this table, if a 400 psi injection pressure change were to occur in a well completed with 5 1/2" casing and 2 7/8" tubing in a relatively highly permeable formation (50 darcy-feet), a change of about 12 psi in annulus pressure could be expected (400 psi/34). As the table demonstrates, the annulus pressure change is rather small relative to an applied injection pressure change for a well with a large annulus. On the other hand, in wells with a small annulus, the annulus pressure change is of more consequence, but is still small compared to temperature-induced changes.

In many larger injection operations, the temperature of the injected fluid is kept relatively constant, thus in these systems seasonal temperature variations may be the only temperature changes noted. However, in some injection operations, the injected fluid temperature may change significantly on a more irregular basis. Temperature changes may be due to 1) varying storage time at the surface for fluid; 2) variations in temperature at the oil-water separation facility; or 3) the need to transport the salt water from the point of collection to the injection well. Changes in the temperature of the injected fluid will cause the annulus fluid to undergo a volume change due to thermal expansion or contraction, and will also cause a volume change in the annulus, due to thermal expansion or contraction of the tubing and casing. The latter change is due to the differences in the coefficients of thermal expansion of the annulus fluid (i.e. water) and the casing and tubing (i.e. steel). With injected fluid temperature changes, the annulus thus undergoes several changes, the net result of which is measured as an annulus fluid pressure change at the surface.

Langlinais (1981) has identified the variables involved in annulus pressure change due to injected fluid temperature change as: 1) depth of the well; 2) injected fluid temperature; 3) mechanical configuration of the well (size of the annulus); 4) geothermal

TABLE 4. CHANGE IN ANNULUS PRESSURE/CHANGE IN INJECTION PRESSURE RELATIONSHIPS (LANGLINAIS, 1981).

	$\frac{\Delta P \text{ injection}}{\Delta P \text{ annulus}}$	
Geometry (casing x tubing)	50 darcy ft	5 darcy ft
9⅝" x 7"	±6.2	±5.9
7" x 4½"	±13	±11
7" x 3½"	±38	±29
7" x 2⅞"	±120	±90
5½" x 2⅞"	±34	±26

gradient; and 5) heat exchange coefficients. In addition, because of the effect of thermal expansion of the tubing and casing, a calculated volume change in annulus fluid will not result in a pressure change as though the annulus were a fixed volume.

Graphs presented in Appendix B (Langlinais, 1981) depict the response of annulus pressure to injected fluid temperature. In these graphs, annulus pressures (on the vertical axis) correspond directly to annulus volume changes due to temperature changes. Positive pressure indicate expansion of annulus fluid and negative pressures indicate contraction of annulus fluid. Each graph represents several depths for a given well geometry. The surface temperature is assumed to be a constant 69°F and the geothermal gradient 1.3°F/100 ft. These graphs can be used to determine the expected annulus pressure changes for injected fluid temperature changes, but cannot give annulus pressure at a particular injection temperature, since other variables (i.e. level of annulus fluid in the well) are not considered.

As an example, suppose fluid at a temperature of 85°F is being injected into a 400 foot deep injection well with 4 1/2" tubing and 7" casing. If the injected fluid temperature were to increase to 95°F, an annulus pressure increase of about 300 psi is expected. The graphs take into account the fact that injected fluid heats the annulus fluid only to the depth at which injected fluid temperature is equal to the temperature outside the well bore, and below that depth the injected fluid cools the annulus fluid. A 1000 foot well with the same injection fluid temperature change, then, would experience an annular pressure increase of nearly 400 psi.

In creating these relationships, Langlinais (1981) assumed that the well was allowed to achieve steady-state equilibrium conditions. However, because injected fluid temperatures may vary somewhat on a daily basis, and may not allow the well to reach steady-state conditions at any temperature, these relationships may not always hold true. Langlinais (1981) recommends that in predicting the response of a well to injected fluid temperature changes, a value of 65% of peak change be used. As an example, if injection temperature in a 3000 foot deep well with a 5 1/2" diameter casing and 2 3/8" diameter tubing reaches a maximum temperature of 95°F and a minimum temperature of 85°F on a daily basis, there is a 10°F temperature change over each day; the average temperature of injected fluid is 90°F. Taking 65% of the 10°F temperature change, or 6.5°F, and spreading that 6.5°F range on either side of the 90°F average, values of approximately 93.2°F and 86.7°F are obtained. Thus, for this well, a daily annulus pressure variation of approximately 260 psi could be expected.

It is important to note from this discussion that even slight injection temperature changes result in a noticeable annulus pressure change. Temperature changes as small as 2°F may result in as much as a 100 psi pressure change. Therefore, the interpretation of annulus pressure monitoring results must take injected fluid temperature into account. This may necessitate the monitoring of injected fluid temperature to ensure that pressure changes noted at the surface are due solely to changes in temperature in injected fluid and not to possible casing, tubing or packer leaks.

COST

The cost for monitoring annulus pressure is minimal, since the equipment needed to perform the monitoring (i.e. pressure gauges) is relatively inexpensive and is either already installed on the wellhead, or can be readily installed (with the proper fittings) on a temporary basis. Time and manpower requirements for both continuous monitoring and periodic monitoring are minimal, and consist simply of the time and manpower required to take periodic pressure measurements or to monitor the continuous recording device.

No accurate figures regarding the cost of implementing an annulus pressure monitoring program were available at the time of writing of this report, although in comparison with other mechanical integrity testing methods, costs are very low.

ADVANTAGES AND DISADVANTAGES

The primary advantage to monitoring of annulus pressure is that because the technique provides a "real-time" measurement of well integrity, the well does not have to be taken out of service for monitoring to be performed. This is a significant advantage to operators because it minimizes "down time" for the well. This adds to the cost advantage of this method, which is already significantbecause manpower requirements are low, little if any specialized equipment is needed to perform the test, and the test can be conducted in a very short period of time. Another advantage of annulus pressure monitoring is that it provides for early determination of a mechanical integrity problem, because the well is normally monitored on a regular and frequent (i.e. daily, weekly or monthly) basis. Compared to other mechanical integrity testing methods, which may be used only once every year or once every five years, annulus pressure monitoring provides a more timely indication of well failure.

There are several potential drawbacks to using annulus pressure monitoring as a means of determining mechanical integrity of an injection well. One disadvantage of this technique is that several variables may complicate the interpretation of monitoring results. As previously discussed, variations in injection pressures and injected fluid temperatures can cause significant changes in annulus pressures. If these are not accounted for during the period of monitoring, erroneous monitoring data may result, which may lead to faulty conclusions regarding the mechanical integrity of the well.

Another disadvantage is that it is possible that monitoring of annulus pressure would not detect the presence of a leak in the tubing, packer, or casing if the fluid pressure on the outside of the annulus is in equilibrium with the pressure imposed on the annulus. It is possible to vary annulus pressure periodically so that the presence of leaks at equilibrium with any one pressure become apparent thus eliminating this problem for wells in which pressure is maintained on the annulus.

Annulus pressure monitoring is a method limited to use in wells completed with tubing and packer; thus it cannot be used in many operating injection wells. Also, because of the nature of the method, it cannot be used to detect the presence of fluid migration behind casing.

EXAMPLES

No examples of annulus pressure monitoring were available at the time of writing of this report.

REFERENCES

Langlinais, Julius, 1981, Waste disposal well integrity testing and formation pressure build-up study; Final Report submitted to Louisiana Department of Natural Resources, September, 1981, 56 pp.

Owens, Sam R., 1975, Corrosion in disposal wells; Paper presented at the National Association of Corrosion Engineers, South Central Meeting, October 1974, Houston, Texas, 3 pp.

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SECTION 6

PRESSURE TESTING

SYNOPSIS

Pressure testing is one of the standard industry procedures utilized to detect the presence of leaks in the casing, tubing, or packer of an injection well. In fact, it is required in many oil-producing states as the means of testing the integrity of casing in new production and injection wells at the time that the casing is cemented into the borehole. Pressure testing may also be required on wells newly converted from production to injection and on wells in which major workovers have been performed.

The type of pressure test performed on an injection well is dependent on the construction details of the well, though certain general testing procedures apply to all wells. Pressure is applied to the liquid-filled, shut-in casing or casing-tubing annulus by one of several means, usually either a drilling rig mud pump or service pumping equipment. Liquid pressure is generally used, as gas pressure may not generate useful test results. The amount of pressure used in the test, and the period of time the pressure is held on the well depend on the requirements of individual state regulatory agencies. Maintenance of the shut-in pressure during the test provides evidence of the mechanical integrity of the well. If a significant pressure die-off is noted during the period of the test, the casing or one of the other well components (tubing or packer) is considered to be leaking.

PRINCIPLES

The principle of a pressure test is simple and straightforward. Liquid pressure applied to a fixed volume enclosed vessel, such as an injection well closed at the bottom and the top, should remain constant if there are no leaks in the well. Because a volume of liquid requires only a relatively small volume change to yield a detectable pressure change, any leak in the vessel being pressurized should make itself evident as a pressure drop (if liquid pressure outside the vessel is less) or pressure increase (if liquid pressure outside the vessel is greater). Thus, it is possible to use pressure changes, as monitored during a short-term test conducted at the surface, to determine the presence of leaks in the casing of an injection well, provided the test is properly conducted.

EQUIPMENT

Provided that the well to be tested is equipped with suitable wellhead pressure gauges, the only equipment necessary to conduct a pressure test is a device to generate fluid pressure. Generally, a drilling rig mud pump or service pumping equipment, which can supply the desired pressures, are used for pressuring well casing. As these are the two most common oil-field practices for applying pressure to wells for various purposes, this equipment is generally available through either drillers or well servicing contractors.

If the well to be tested is not equipped with a suitable wellhead, the well must first be outfitted with that equipment. The wellhead should have pressure gauge connections, so that the pressure applied to the casing or casing-tubing annulus can be monitored during the period of the test, and a recording device to record any pressure fluctuations.

PROCEDURES

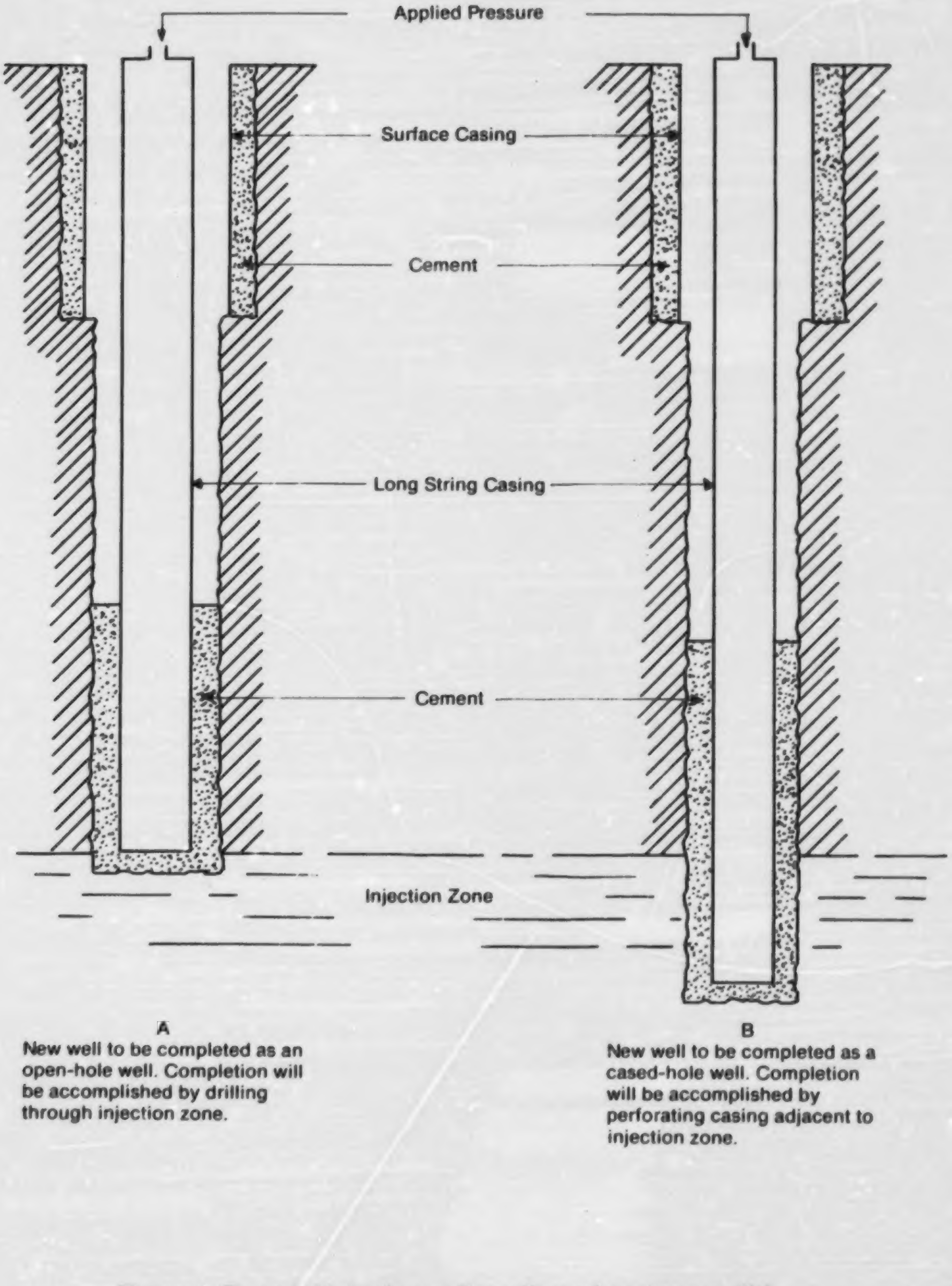
The procedures for pressure testing an injection well differ depending on whether the well to be tested is a new well or an existing well, and further differ in existing wells depending on the construction details of the well. The following injection well configurations are described in this document:

- New wells (Figure 4)
- Existing wells without tubing and packer (Figure 5A)
- Existing wells with tubing and packer (Figure 5B and 5C)
- Existing wells with tubing and without packer (not illustrated)

Certain general procedures, which follow, apply to pressure testing for any of the above well configurations.

The pressure is applied by the chosen method, either to the shut-in casing or to the casing-tubing annulus, and monitored for a period of time. The pressure used for testing, the period of time the pressure is monitored and the amount of pressure variation ("bleed-off") allowed are all dependent on the requirements of the individual state UIC program. Table 5 illustrates the pressure testing requirements for fifteen states which have these requirements. A common requirement of many states is that the well be pressurized to 300 psi or the maximum allowable injection pressure, whichever is greater, and the pressure monitored for 30 minutes. The amount of pressure bleed-off allowed is left to the discretion of the individual state regulatory agencies, and ranges from no bleed-off allowed to ten percent bleed-off allowed.

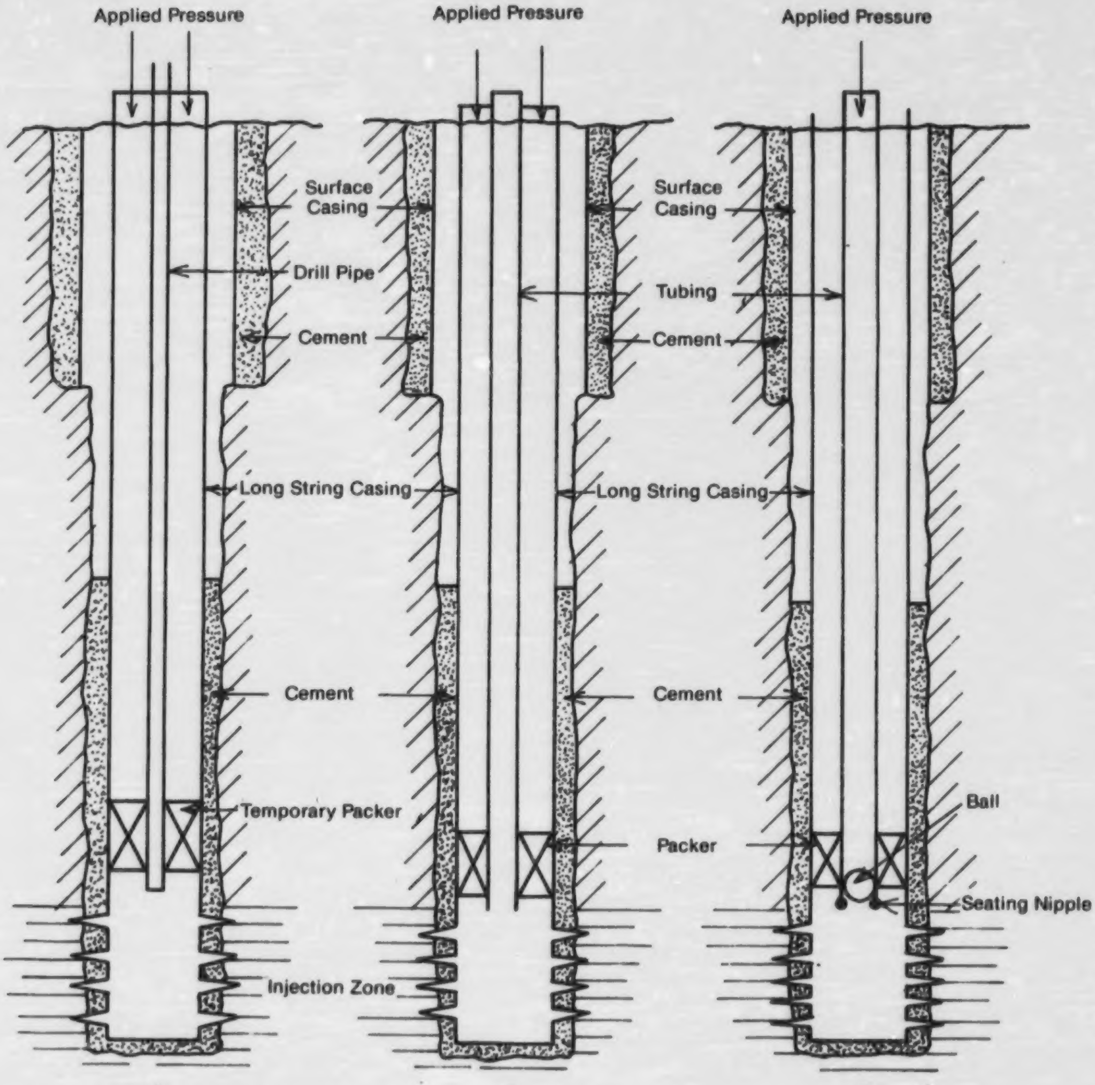
Pressure tests are nearly always conducted on the entire length of casing or tubing in the well. However, it may be possible to



A
New well to be completed as an open-hole well. Completion will be accomplished by drilling through injection zone.

B
New well to be completed as a cased-hole well. Completion will be accomplished by perforating casing adjacent to injection zone.

Figure 4. Types of injection well configurations (new wells).



A
Well with casing, without tubing and packer, fitted with temporary packer for pressure test

B
Well with casing, tubing and packer

C
Well with casing, tubing, packer and seating nipple

Figure 5. Types of injection well configurations (existing wells).

TABLE 5. STATE PRESSURE TESTING REQUIREMENTS FOR CLASS II INJECTION WELLS

State	Pressure Required (psi)	Length of Test (minutes)	Allowable Bleed-Off (percent)
Alabama	0.2 x depth to injection interval, not to exceed 1,500 psi	30	10
Arkansas	300-750 (sliding scale)	30	10
Colorado	300 or minimum injection pressure, whichever greater	30	5
Florida	0.2 x depth to injection interval	30	10
Kansas	100 or maximum authorized injection pressure, whichever greater	30	N/A
Kentucky	100 or maximum allowable injection pressure	N/A	N/A
Louisiana	300 or maximum allowable injection pressure, whichever greater	30	*
Michigan	Minimum of 133 percent of expected operating pressure	N/A	N/A
Mississippi	500	30	10
Nebraska	125 percent of maximum authorized injection pressure or 300 psi, whichever greater	N/A	N/A
North Dakota	1,000	15**	0
Ohio	300 or maximum allowable injection pressure, whichever greater	15	5
Oklahoma	*	15	10
Texas	500 or maximum authorized injection pressure, whichever less; at least 200 psi	30	10
West Virginia	2,000	20	5
Wyoming	1,000 psi or maximum injection pressure, whichever greater	15	10

*left to discretion of state inspector
**require longer test if any pressure loss is noted.
N/A=not available

utilize a dual packer system (Figure 6) or a retrievable bridge plug or temporary packer to isolate specific intervals in a well for staged pressure testing. Pressure may then be exerted on the chosen interval via tubing between the dual packers, or an increasingly shorter length of casing or tubing above the retrievable bridge plug or temporary packer. This procedure may be repeated as necessary in any interval in the well, or the packers may be reset to any separation to test any length of casing greater than 3 feet. This procedure provides a means of not only detecting but also locating a leak. However, it is more time-consuming than "normal" pressure testing.

Rome and LaRussa (1978) describe a tool which can be used for testing specific intervals of tubing or well casing for leaks. The tool (Figure 7) consists of longitudinally spaced packers which can be expanded to isolate a portion of the tubing or casing string for subjecting the isolated portion to a pressure test. Liquid pressure is applied to the isolated portion of the tubing or casing through flow controllers which include a liquid diffuser that prevents direct impingement of the testing liquid onto the inside coating of the tubing, thereby preserving the integrity of the coating. The spaced packers are expanded by piston and cylinder assemblies arranged so that the tool does not move or change in length in order to compress the packers when in operation. A swab structure on the bottom end of the tool prevents the testing liquid from running down the tubing or casing as the tool is moved from one position to another.

Normally, liquid is used to pressurize injection wells. Langlinais (1981) suggests that the practice of using gas to pressurize injection wells should be avoided because the loss of fluid from the well may not be detectable as a pressure decrease. This is primarily because of the difference in compressibility between gas and liquid. A given volume of gas requires a relatively large volume change to yield a detectable pressure change, whereas the same volume of liquid will yield a detectable pressure change with a relatively small volume change.

The following example, given in Langlinais (1981) emphasizes the difference in pressurizing with gas and with fluid:

If the volume of gas used to pressurize the column of fluid in the casing is approximately one barrel at a pressure of 500 psi, then in a well utilizing 7 5/8 inch diameter casing with 3000 feet of 2 3/8 inch diameter tubing, a one gallon leak results in a pressure loss of approximately 12 psi. If the same pressure were applied with water, then a 50 psi pressure loss results. On the other hand, if the original gas volume used to pressurize the column of fluid in the casing had been two barrels, then the pressure loss would only have been half as much, or 6 psi.

In this example, if the observation time were 30 minutes, the leak in the well would amount to about 48 gallons per day, or 17,500

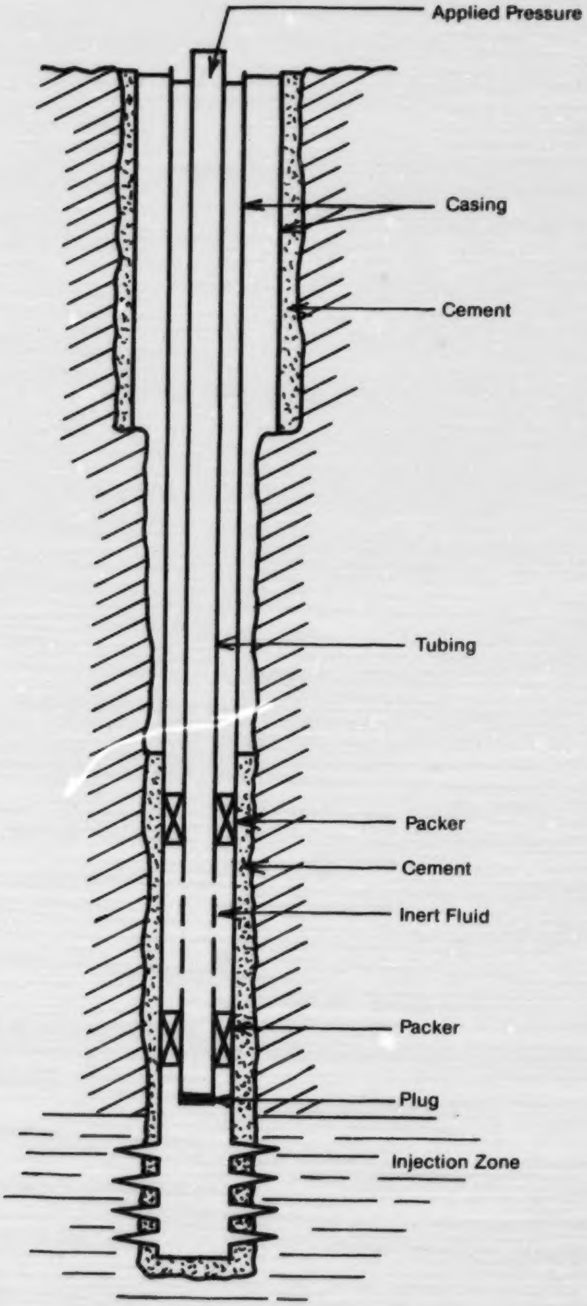


Figure 6. Dual packer system used for staged pressure tests.

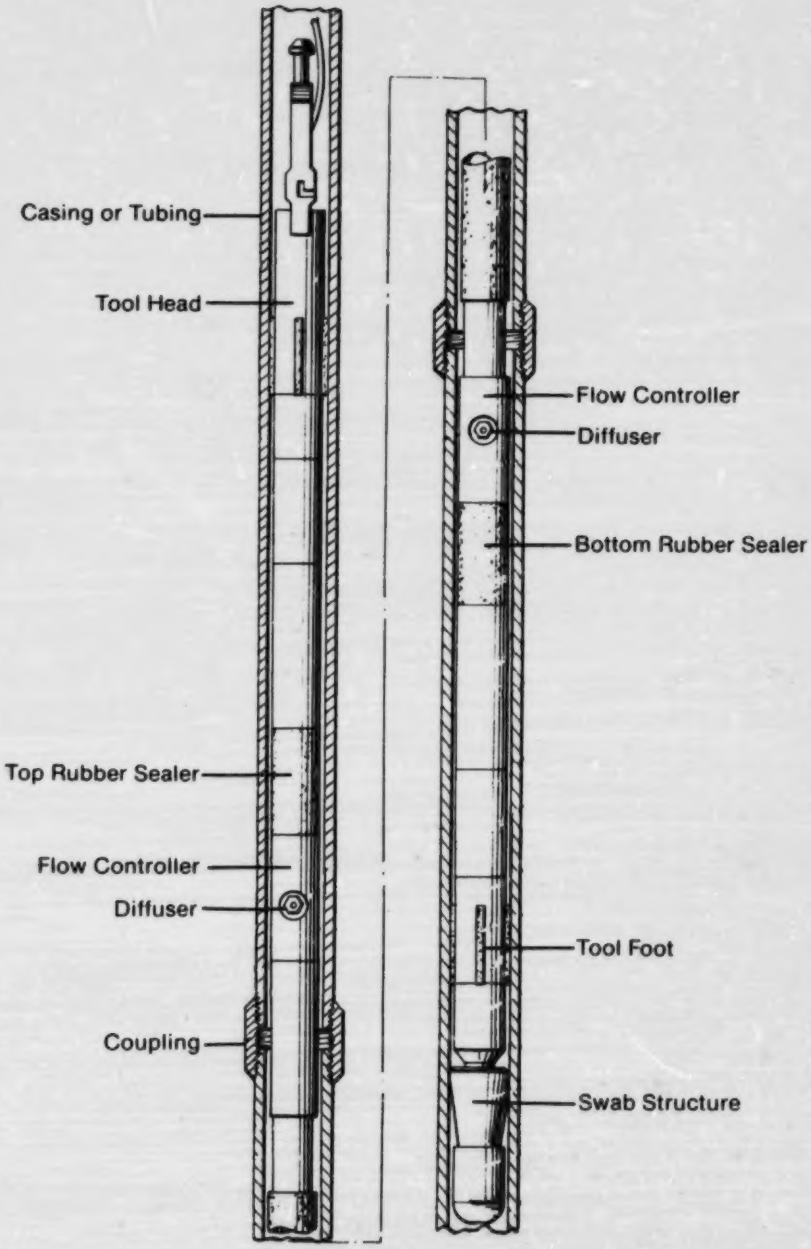


Figure 7. Tool utilized for testing specific intervals of well casing or tubing for leaks (After Rome and LaRussa, 1978).

gallons per year (assuming constant operation). This could certainly be a "significant leak," as defined by the UIC program criteria. Thus, it is clear that if gas is used to pressurize the well, a leak of this size may not be detected or may be accepted if even a five percent pressure die-off is permitted by testing criteria.

The pressure testing procedures which follow are those which are specific to each of the four well configurations previously described.

New Wells

Following the completion of a new injection well (Figure 4), the well casing is generally tested as a matter of course to assure the operator and to satisfy regulatory concerns that no leaks exist in the casing. This test is usually performed after the casing has been installed and cemented in place, but prior to perforating (if a cased-hole completion) or drilling out the casing shoe (if an open-hole completion) so that the casing is entirely sealed at the bottom. The casing is then shut in at the top with a wellhead seal or blowout preventer and the casing is filled with fluid. The well should be allowed to remain idle for several hours so that the temperatures of the fluid inside the casing and the formation fluids at depth can equilibrate; pressure can then be applied to the well. Ignoring this step may cause problems in the interpretation of the data obtained from the test. This test is a test of the entire length of casing.

Existing Wells Without Tubing and Packer

A pressure test of the casing of a well without tubing and packer (Figure 5A) requires the installation of a temporary packer or retrievable bridge plug above the injection zone prior to testing. Once the temporary bottom seal is effected, the well can be tested in the same manner as a new well, the only difference being that the length of casing below the temporary seal is not tested. Care should be taken to choose the correct type of packer to ensure that the packer is able to withstand the pressure applied to the column of fluid above it. Otherwise, the packer may leak, resulting in misinterpretation of the test results.

Existing Wells With Tubing and Packer

The standard procedure to test the mechanical integrity of wells with tubing and packer (Figure 5B) is to first apply pressure to the fluid-filled annulus between the tubing and the casing and monitor the pressure. To conclusively test the well, the hydrostatic pressure in the annulus at any depth must exceed both the formation pressure and the hydrostatic pressure in the tubing. This will allow for a determination of the mechanical integrity of the casing, tubing and packer as a unit. However, this test does not permit the operator to determine which of these three well components may have a leak, if one should be present. A leak in any one of these components would manifest itself as a pressure loss at the surface.

This type of test should be conducted with the tubing shut in (i.e. injection should be ceased for the period of the test). Prior to conducting a pressure test on a well with tubing and packer, the type of packer in the well should be known since this will determine the amount of pressure which can be applied to the annulus. If the packer in the well is a compression-set packer, in which the weight of the tubing is placed on the packer to effect a seal, then additional annulus pressure will tend to increase the integrity of the seal. On the other hand, if the packer is of the tension-set type, in which tension is needed to effect a seal, additional annulus pressure may cause the packer to unseat. The possibility of unseating the packer will be determined by the original tubing tension at the time the well was completed (Langlinais, 1981). If the packer is set high above the perforations, the packer should be lowered so that a test of the entire length of casing and tubing above the perforations is possible. Moving of a packer which has remained in place for a long period of time nearly always necessitates removing the packer and replacing the sealing elements, which may be a time-consuming operation.

Other variables which should be known prior to conducting a pressure test on a well include casing yield strength, wall thickness, and type of casing connection. All of these will have some bearing on the amount of pressure which can be applied to a particular well without causing failure of one of the well components.

If the injection well must maintain some flow and cannot be shut in, a dynamic test, or one which is conducted while the well is injecting, must be performed. The most dependable method to conduct a dynamic test is to continuously monitor the tubing injection pressure, the injected fluid temperature and the tubing-casing annulus pressure simultaneously. Short-term variations in injection pressure and injected fluid temperature, though uncommon, may complicate the test results and make it more difficult to recognize leaks in the casing, tubing or packer in this type of test. A discussion of the implications of injection pressure and temperature influences on annulus pressure is given in Section 5 "Monitoring of Annulus Pressure."

In wells with tubing and packer completions in which the tubing is fitted with a seating nipple at the base of the tubing, (Figure 5C) it is possible to pressure test the tubing independently. In wells with tubing and packer completions in which the tubing is not fitted with a seating nipple, it is still possible to independently pressure-test the tubing by installing a retrievable tubing plug. A downhole shutoff valve, which opens and closes by tubing rotation, could also be utilized to shut in the tubing. The presence of either the seating nipple, the tubing plug or the shutoff valve thus allows the independent determination of tubing mechanical integrity. The test is performed by shutting in and pressurizing the fluid-filled tubing and monitoring for pressure loss.

Existing Wells With Tubing and Without Packer

A pressure test of the casing of a well with tubing but without a packer can only be accomplished after the tubing has been pulled and a temporary packer or retrievable bridge plug has been set above the injection zone. After this is done, the procedure for testing the casing is essentially the same as for a well without tubing and packer.

A pressure test of the tubing in this type of well can be accomplished if the tubing is fitted with a seating nipple or can be fitted with a tubing plug at the bottom. The tubing can then be sealed at the well head and pressure applied on the tubing. The tubing could be inspected at the surface for defects after it has been pulled from the well, but this may not be effective in finding small leaks or leaks at tubing joints.

Interpretation

Interpreting the results of a pressure test is a relatively straightforward task. Generally, a surface recording device will have been used to record pressure test results; the results are displayed on either a strip chart or a disc chart. Maintenance of constant pressure as applied either to the casing or to the casing-tubing annulus results in a straight-line chart recording over the period of the test. Any change in pressure, either an increase or a decrease, will result in a deviation from the straight-line recording.

If after the prescribed period of time the pressure applied to the well does not change, it can be concluded that the well does not have a leak. If there is a slight pressure decrease, it may be due to air dissolving in the fluid in the well, or to the failure of temperature in the well bore to stabilize with formation temperatures before the test is performed (Langlinais, 1981). The pressure test should be repeated if this situation is encountered. If, after the well is pressurized a second time, there is a continued and significant pressure die-off during the period of the test, it is likely that a leak in the well exists. If a leak in the well is detected, the rate at which the fluid is being lost and thus the size of the leak can be estimated using methods outlined by Langlinais (1981). It may not be possible, without further testing, to determine the location of the leak or to determine which component of the well (casing, tubing or packer) is leaking.

There may also be pressure increases immediately following pressurization of the well. These are usually due to thermal expansion of the fluid in the well, which should stabilize after a short period of time. Another cause of increased wellhead pressure may be leakage into the well from high-pressure zones in the subsurface that were not adequately isolated from the well bore by the packer.

COST

Cost for a pressure test will vary a great deal depending on the construction details of the well, the distance of the well from the service contractor, and a number of other variables. Costs for pressure testing an operating well, including pump and packer rental, time allotted to testing, a round trip to and from the well for the service contractor, and time required to pull tubing, set and remove the retrievable packer and reset the tubing are estimated to be in the range of $2000 to $10,000 (Dimatteo, personal communication, 1983).

ADVANTAGES AND DISADVANTAGES

In comparison to other mechanical integrity tests, pressure tests are relatively inexpensive and easy to perform in both new and existing injection wells. They generally produce results which are simple and straightforward with regard to interpretation, if they are conducted properly. For these reasons, pressure testing is perhaps the most widely utilized means of determining mechanical integrity.

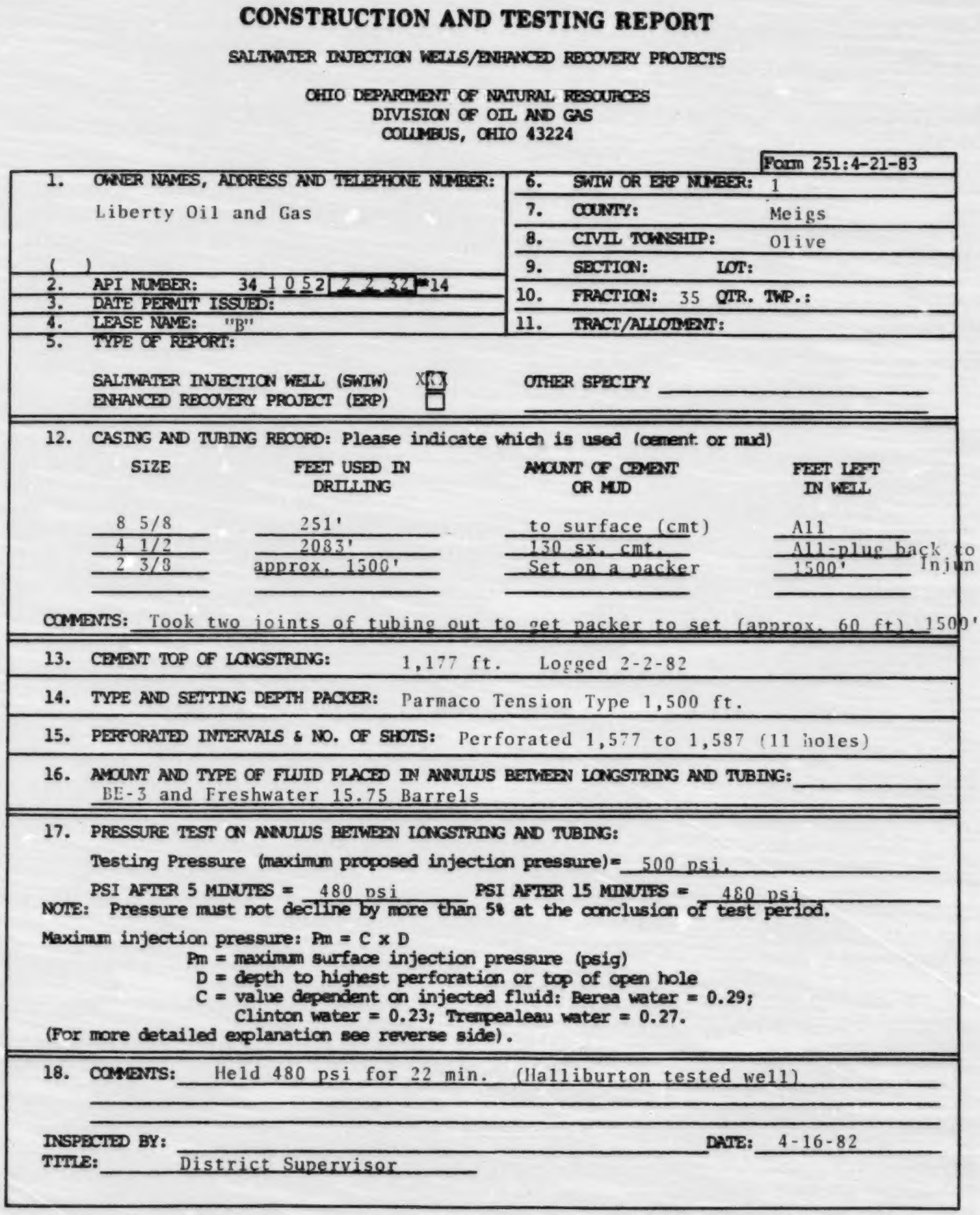
In many cases, pressure testing of a well takes less than one day's time. In some cases, however, pressure testing may take up to several days, during which the well will be out of service.

Pressure testing of an injection well which serves as a salt-water disposal well, particularly where the well of concern is the only disposal well for a producing field, presents the problem of what to do with the salt water produced during the period of the test. The salt water must either be stored on site, hauled off-site, or the production shut in. Some disruption of production is inevitable if the injection well is out of service long enough to overload the alternative disposal methods.

If excessive pressures are applied to the well, the pressure test itself may cause the well to develop a leak in either the casing or the tubing, aggravating already deteriorating well conditions (i.e. corrosion).

EXAMPLES

Figures 8 and 9 illustrate the results of a pressure test run on a salt water injection well in Meigs County, Ohio. Figure 8 is the completed state form for reporting of the pressure test on the annulus between the injection tubing and the long string; Figure 9 graphically displays the test. Initially a corrosion inhibitor and fresh water was run down the annulus, then the lines were tested and the annulus pressure tested. During the initial test, the pressure did not stay



CONSTRUCTION AND TESTING REPORT

SALTWATER INJECTION WELLS/ENHANCED RECOVERY PROJECTS

OHIO DEPARTMENT OF NATURAL RESOURCES
DIVISION OF OIL AND GAS
COLUMBUS, OHIO 43224

Form 251:4-21-83

1. OWNER NAMES, ADDRESS AND TELEPHONE NUMBER: Liberty Oil and Gas
( )
2. API NUMBER: 34 1 0 5 2 2 2 32 14
3. DATE PERMIT ISSUED:
4. LEASE NAME: "B"
5. TYPE OF REPORT:
SALTWATER INJECTION WELL (SWIW) X☒
ENHANCED RECOVERY PROJECT (ERP) ☐
OTHER SPECIFY

6. SWIW OR ERP NUMBER: 1
7. COUNTY: Meigs
8. CIVIL TOWNSHIP: Olive
9. SECTION: LOT:
10. FRACTION: 35 QTR. TWP.:
11. TRACT/ALLOTMENT:

12. CASING AND TUBING RECORD: Please indicate which is used (cement or mud)

SIZE	FEET USED IN DRILLING	AMOUNT OF CEMENT OR MUD	FEET LEFT IN WELL
8 5/8	251'	to surface (cmt)	All
4 1/2	2083'	130 sx. cmt.	All-plug back to Injun
2 3/8	approx. 1500'	Set on a packer	1500'

COMMENTS: Took two joints of tubing out to get packer to set (approx. 60 ft). 1500'

13. CEMENT TOP OF LONGSTRING: 1,177 ft. Logged 2-2-82

14. TYPE AND SETTING DEPTH PACKER: Parmaco Tension Type 1,500 ft.

15. PERFORATED INTERVALS & NO. OF SHOTS: Perforated 1,577 to 1,587 (11 holes)

16. AMOUNT AND TYPE OF FLUID PLACED IN ANNULUS BETWEEN LONGSTRING AND TUBING: BE-3 and Freshwater 15.75 Barrels

17. PRESSURE TEST ON ANNULUS BETWEEN LONGSTRING AND TUBING:

Testing Pressure (maximum proposed injection pressure)= 500 psi.

PSI AFTER 5 MINUTES = 480 psi PSI AFTER 15 MINUTES = 480 psi

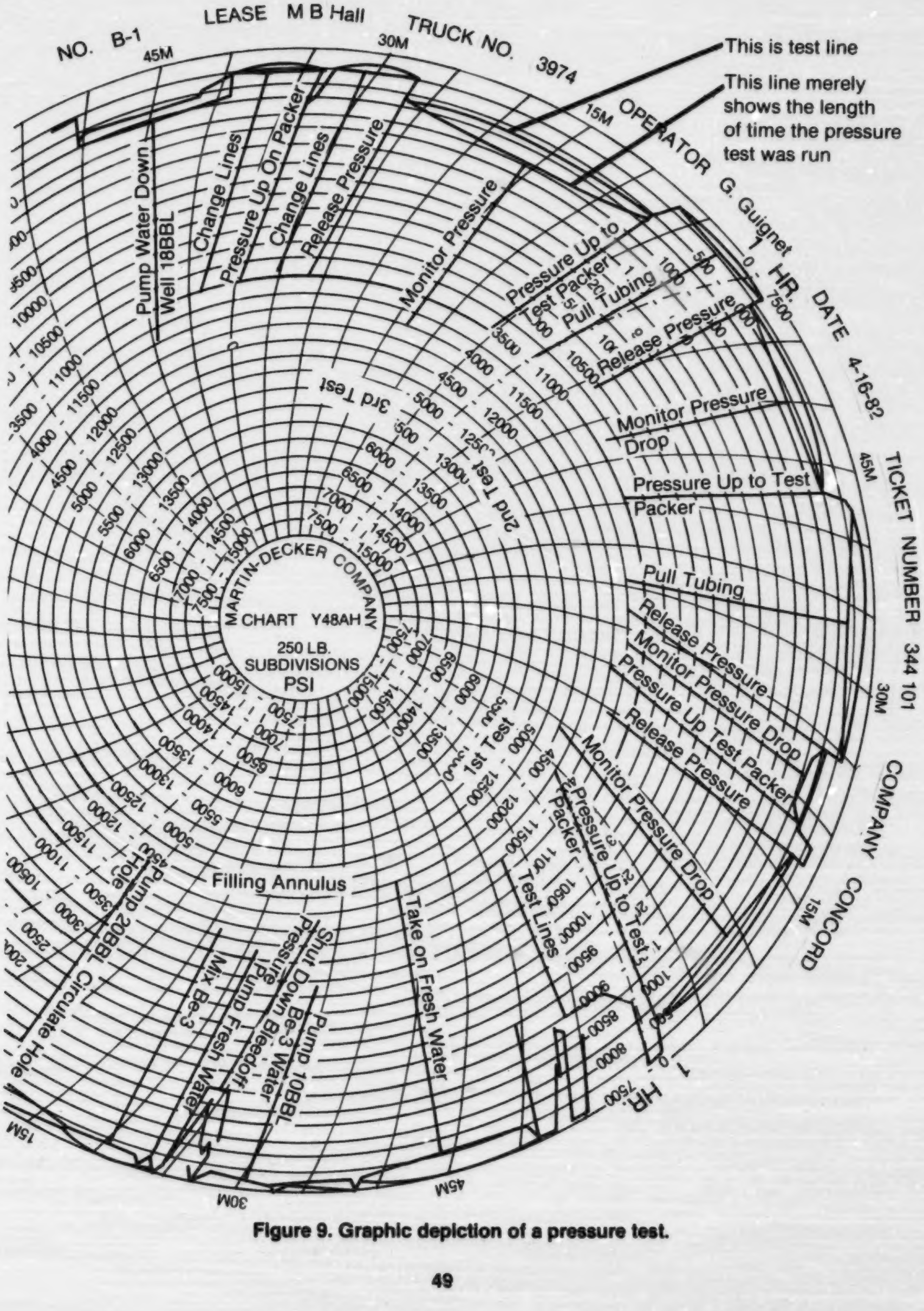
NOTE: Pressure must not decline by more than 5% at the conclusion of test period.

Maximum injection pressure: $P_m = C \times D$
P_m = maximum surface injection pressure (psig)
D = depth to highest perforation or top of open hole
C = value dependent on injected fluid: Berea water = 0.29; Clinton water = 0.23; Trempealeau water = 0.27.
(For more detailed explanation see reverse side).

18. COMMENTS: Held 480 psi for 22 min. (Halliburton tested well)

INSPECTED BY: DATE: 4-16-82
TITLE: District Supervisor

Figure 8. Completed state form for reporting of the pressure test on the annulus between the injection tubing and long string.



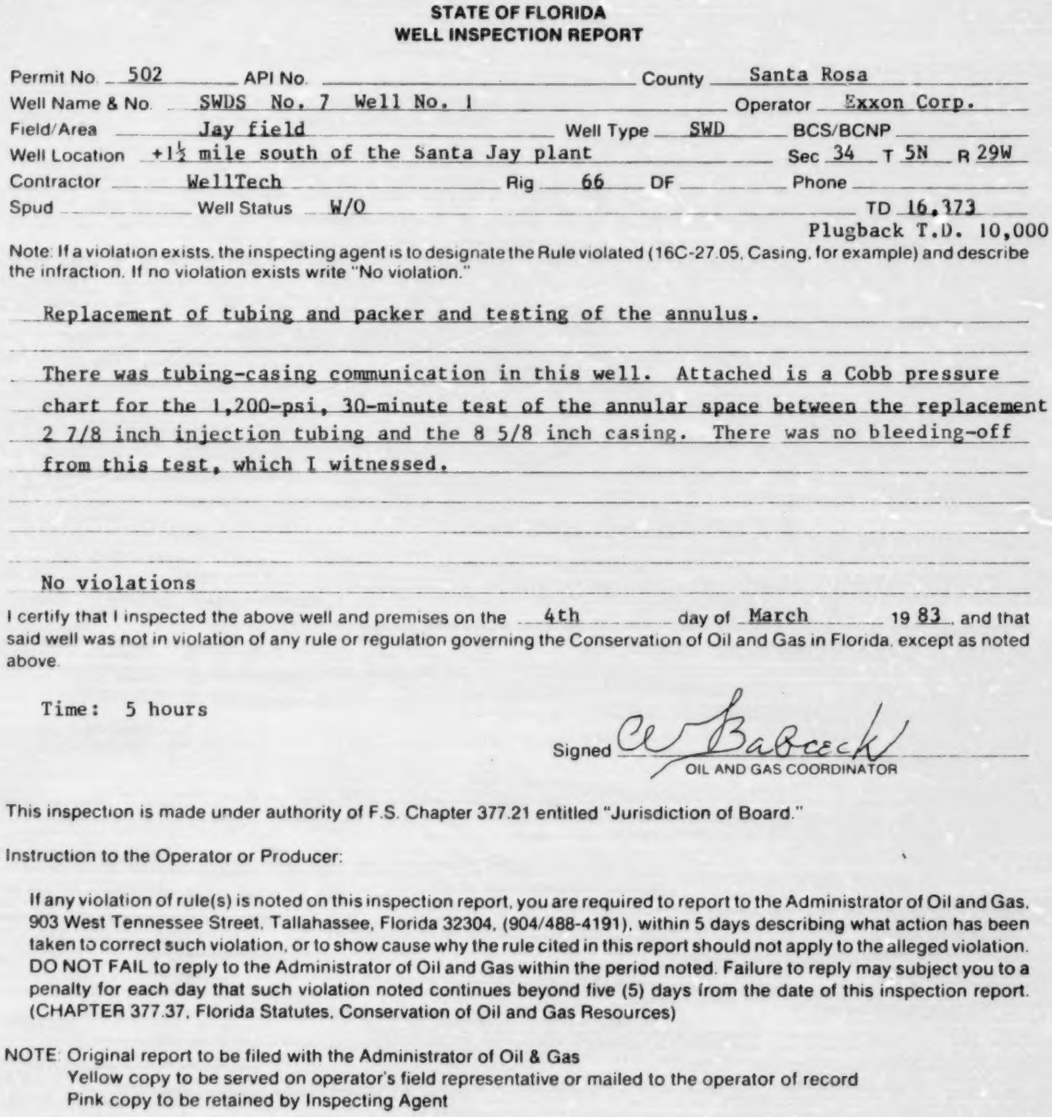
This is test line

This line merely shows the length of time the pressure test was run

Figure 9. Graphic depiction of a pressure test.

within the 5 percent allowable pressure bleed-off. The tubing was pulled up to tighten the packer and the pressure test repeated. Again, the test failed, the tubing was pulled up once more and the annulus retested. This time the pressure remained within the 5 percent limit and the well met the integrity test (Dailey, personal communication, 1983).

Figures 10 and 11 illustrate a pressure test on a saltwater disposal well in Santa Rosa County, Florida. Figure 10, the state well inspection report, indicates that in this well, in which tubing-casing communication was occurring, the tubing and packer were replaced. The well was subsequently pressure tested at 1200 psi for 30 minutes. Figure 11 graphically displays the test, which shows that there was no bleed off.



STATE OF FLORIDA
WELL INSPECTION REPORT

Permit No. 502 API No. ______ County Santa Rosa
Well Name & No. SWDS No. 7 Well No. 1 Operator Exxon Corp.
Field/Area Jay field Well Type SWD BCS/BCNP ______
Well Location +1½ mile south of the Santa Jay plant Sec 34 T 5N R 29W
Contractor WellTech Rig 66 DF ______ Phone ______
Spud ______ Well Status W/O TD 16,373
Plugback T.D. 10,000

Note: If a violation exists, the inspecting agent is to designate the Rule violated (16C-27.05, Casing, for example) and describe the infraction. If no violation exists write "No violation."

Replacement of tubing and packer and testing of the annulus.

There was tubing-casing communication in this well. Attached is a Cobb pressure chart for the 1,200-psi, 30-minute test of the annular space between the replacement 2 7/8 inch injection tubing and the 8 5/8 inch casing. There was no bleeding-off from this test, which I witnessed.

No violations

I certify that I inspected the above well and premises on the 4th day of March 19 83 and that said well was not in violation of any rule or regulation governing the Conservation of Oil and Gas in Florida, except as noted above.

Time: 5 hours

Signed CW Babcock
OIL AND GAS COORDINATOR

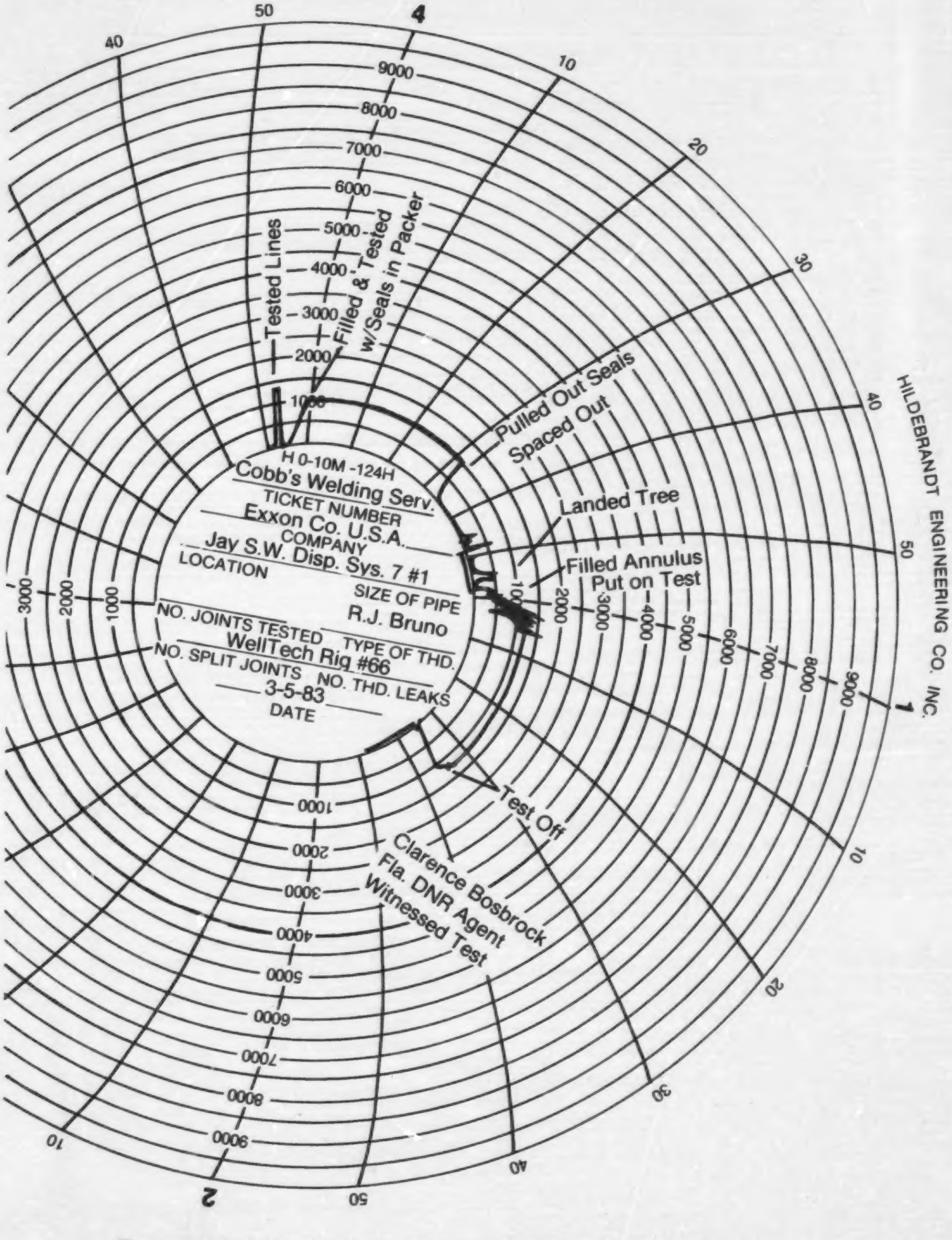
This inspection is made under authority of F.S. Chapter 377.21 entitled "Jurisdiction of Board."

Instruction to the Operator or Producer:

If any violation of rule(s) is noted on this inspection report, you are required to report to the Administrator of Oil and Gas, 903 West Tennessee Street, Tallahassee, Florida 32304, (904/488-4191), within 5 days describing what action has been taken to correct such violation, or to show cause why the rule cited in this report should not apply to the alleged violation. DO NOT FAIL to reply to the Administrator of Oil and Gas within the period noted. Failure to reply may subject you to a penalty for each day that such violation noted continues beyond five (5) days from the date of this inspection report. (CHAPTER 377.37, Florida Statutes, Conservation of Oil and Gas Resources)

NOTE: Original report to be filed with the Administrator of Oil & Gas
Yellow copy to be served on operator's field representative or mailed to the operator of record
Pink copy to be retained by Inspecting Agent

Figure 10. State well inspection report for a pressure test on a salt water disposal well.


H 0-10M -124H

Cobb's Welding Serv.
TICKET NUMBER

Exxon Co. U.S.A.
COMPANY

Jay S.W. Disp. Sys. 7 #1
LOCATION

SIZE OF PIPE

R.J. Bruno
NO. JOINTS TESTED

TYPE OF THD.

WellTech Rig #66
NO. SPLIT JOINTS

NO. THD. LEAKS

3-5-83
DATE

Figure 11. Graphic depiction of a pressure test showing no bleed off.

REFERENCES

Langlinais, J., 1981, Waste disposal well integrity testing and formation pressure build-up study; Final Report submitted to Louisiana Department of Natural Resources, September 1981, 56 pp.

Rome, D.J., Sr. and S.P. LaRussa, 1978, Tubing testing tool; U.S. Patent #4,083,230, April 11, 1978, 9 pp.

SECTION 7

WELL LOGGING: A GENERAL DISCUSSION

INTRODUCTION

The mechanical integrity of injection wells may also be tested using well logging techniques offered by professional well logging companies. A well log is defined as, "a record containing one or more curves related to some property in the wellbore or some property in the formations surrounding the wellbore" (Ransom, 1975). Borehole measurements are obtained by lowering one or more tools into the well and measuring either the characteristics of the formations intersected by the well or the structural components of the well. In the case of an injection well, a log may be run to determine any or all of the following:

1) the presence or absence of casing leaks;

2) the quality of the cement bond to the casing;

3) whether or not channeling of fluid occurs outside the well;

4) the rate and direction of fluid movement into or out of the well at any desired point;

5) casing condition (both internally and externally); and

6) tubing integrity.

Although each log is designed to monitor specific parameters and requires specialized interpretation, the basic logging equipment, need for interpretation and method of determining the cost of each log are similar for most logs. This chapter provides a discussion of those common parameters which pertain to the logs which have applicability for determining the mechanical integrity of injection wells.

LOGGING EQUIPMENT

Even though there is a wide variety of instruments used for well logging, all logging equipment has the same essential elements. The primary components of a logging system include a downhole sensor, an electric cable attached to the tool, a powered winch for hoisting the tool, a calibrated sheave for measuring the length of cable in the hole, a weight indicator, a prime power unit, surface control circuits and a recording system (Guyod and Shane, 1969) (Figure 12). The

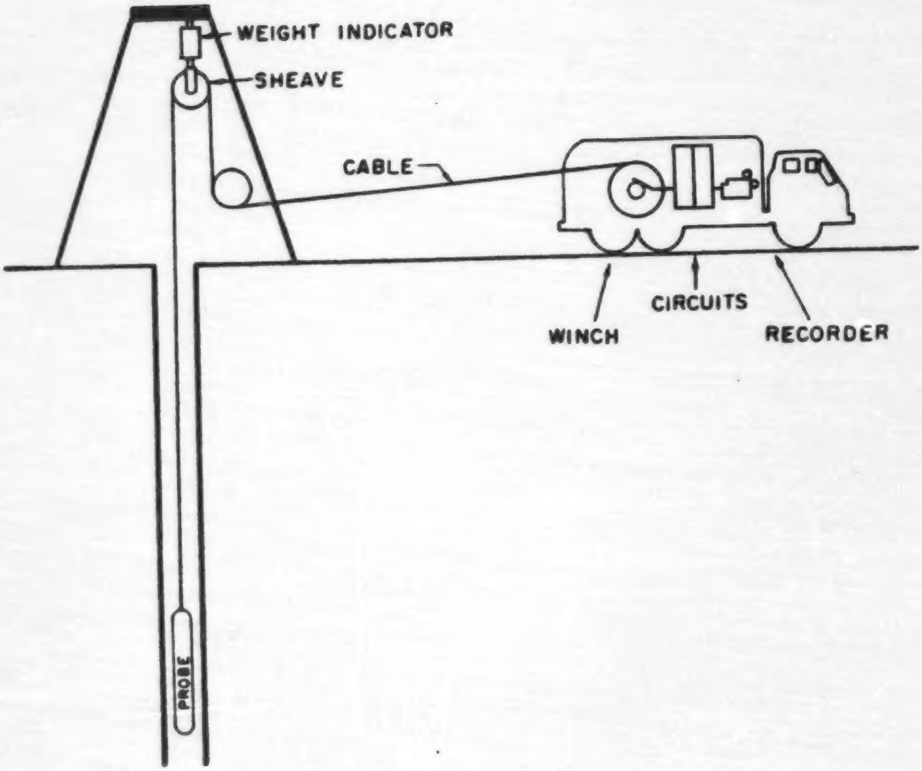


Figure 12. Truck-mounted logging equipment set up at a well (Guyod and Shane, 1969).

downhole sensor is housed in a watertight probe which receives power from the surface and transmits signals to the surface via the logging cable. The probes may either be held in the center of the well by centralizers or allowed to hang freely in the well depending on the requirements of the measurements being made. As the probe is moved up or down the hole, the sensor emits a signal in response to lithology, fluid or borehole parameters (Keys and MacCary, 1971). Logging measurements (with the notable exception of temperature logs) are normally made by lowering the probe to the bottom of the hole and recording data as the probe is raised to the surface. Logging speed depends on the type of measurement performed, but typically ranges from one half to two feet per second (Guyod and Shane, 1969). Some logs, particularly temperature logs, may have to be made at a lower speed.

The signal transmitted by the cable is processed at the surface by electronic equipment. Control panels permit the regulation of (1) logging speed and direction, (2) power to surface and downhole electronics, (3) a signal conditioning, and (4) recorder response (Keys and McCary, 1971) (Figure 13). The logging signals are recorded on chart paper, photographic film and/or magnetic tape as a function of the position of the probe in the hole (Labo, 1978). Logs at various vertical scales are produced by changing the gear ratio in the recorder. The recorder may be driven as a function of time for some logs.

In addition to the actual logging system, other equipment is needed to safely log an injection well. When an injection well is under pressure, pressure control equipment is usually necessary at the site. Logs can be run with or without wellhead pressure control, with or without a full lubricator and with or without a rig depending on the situation and expected pressures (Rust and Feather, 1977). The most typical configuration for a pressurized well is shown in Figure 14. A lubricator is an assembly of wireline pressure control equipment which consists of a blowout preventor, riser, flow tube and stuffing box (Ransom, 1975). The lubricator can be used without a blowout preventor which is usually not necessary in injection wells. A lubricator permits the tools to be introduced into the well without the loss of pressure control, but the use of a rig or some form of supporting mast at the site is necessary (Rust and Feather, 1977).

LOG ANALYSIS

A log is a continuous record of apparent values over pre-selected intervals of the well. In order for these values to be quantified or qualified, a log analysis must be performed. The correct recording and interpretation of well log data are extremely important steps in ensuring useful results. An experienced, professional log analyst must be employed to do log interpretation.

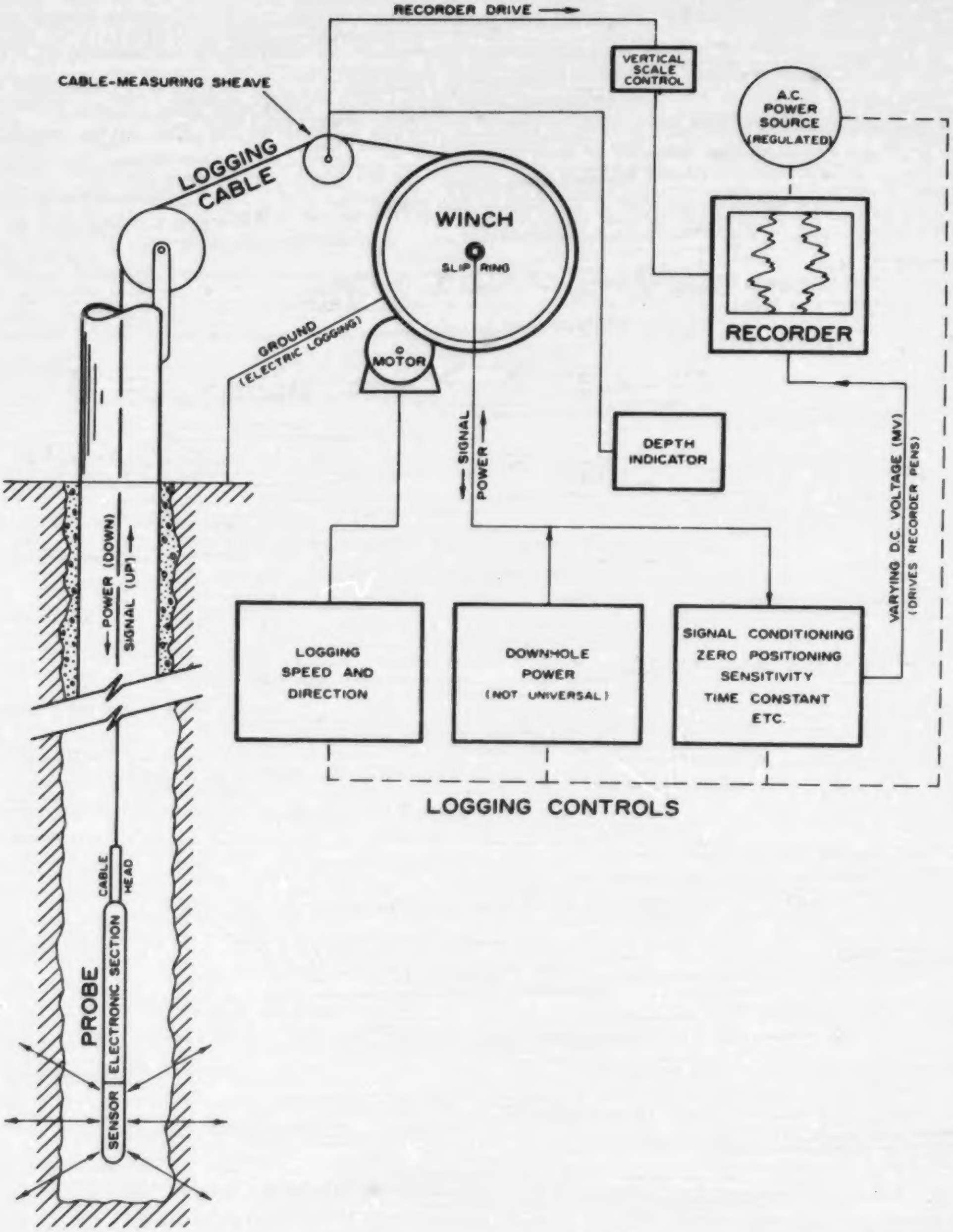


Figure 13. Block diagram of geophysical well logging equipment (Keys and MacCary, 1971).

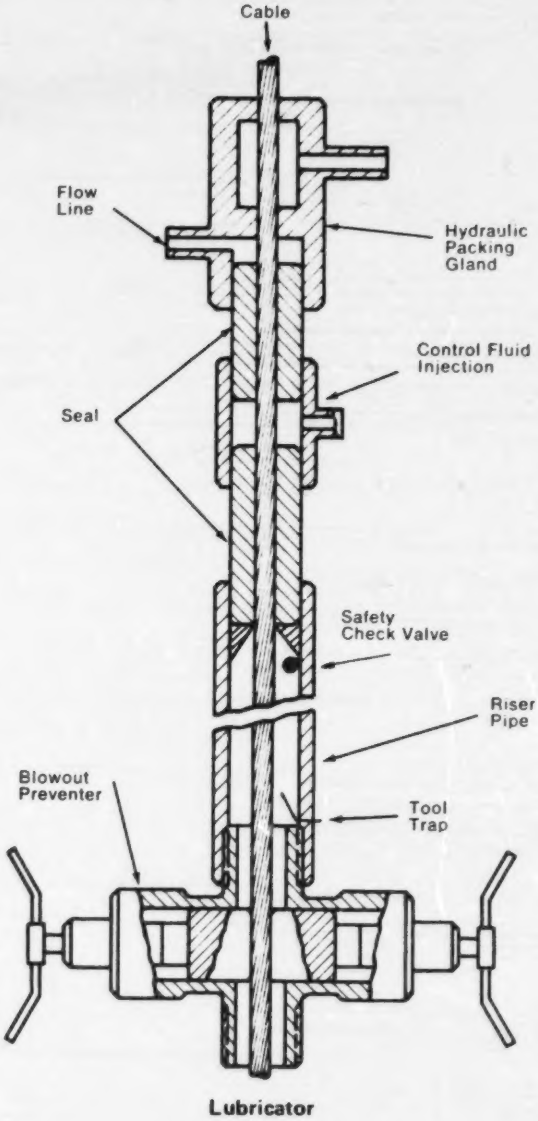


Figure 14. Diagram of a lubricator (Ransom, 1975).

Professional log analysis is available at extra cost from the logging companies which perform the logging service and also from professional well logging consultants. In order to properly analyze a log, the log analyst must be intimately familiar with the principles of each log and have a knowledge of the geologic environment and construction of the well for which the log was obtained. Often more than one type of log is run in a well to enhance the interpretation. Combinations of logs are commonly better-suited to defining down-hole conditions than individual logs. According to Keys and MacCary (1971), the amount of information available from a log is a function of the available background information, the number of different types of logs run, the number of wells logged in a geologic environment and the experience of the log analyst.

When analyzing a log, a log analyst may need to apply correction techniques. Service company interpretation books detailing the many corrections which may be necessary for each individual type of log are widely available. Their availability should not preclude obtaining the services of a professional log analyst to perform the interpretation. Even the most accurately run log is not useful until a proper analysis and interpretation of the readings have been performed.

COST

The prices of well logging services are dependant on the general pricing policy of the company, the type of log, the location of the well and the need for specialized equipment at the site. The basic pricing structure for logging services is relatively standard throughout the industry. The costs associated with most logging services can be divided into two categories: 1) general costs and 2) log-specific costs.

General costs of well logging are usually listed in the front section of each company's price schedule. The general section includes basic fees to transport equipment to the site, charges for manpower to operate the equipment, rental fees of specialized equipment and fees for special conditions encountered either in the well or at the site. The following list details typical items for which logging companies charge fees. Sometimes companies combine fees for items; therefore it is necessary to read each company's pricing schedule to obtain more exact cost for logging a well.

1) Service charge - a standard fee charged for initiating the logging service (Depth charge is not included). Normally this fee is charged for each trip to the well.

2) Mileage - a per-mile fee is charged when the well site is over a designated amount of miles from the well logging company service center.

3) Crew and equipment - fees are normally computed on a per-hour or per-diem basis for all the time that a crew is on the site whether or not a service is being performed. Different fee schedules may apply to different situations. Some companies allot a certain amount of "free time" before charges are initiated.

4) Specialized crew - when logs require the presence of a specialized engineer to either perform or supervise operations, an additional fee is charged. Rates may be computed on a per hour or per-diem basis and normally include travel and lodging costs.

5) Incomplete operations - charges associated with inability to run the log due to well conditions or changes of orders. Normally the service fee plus other specified minimum charges will be assessed.

6) Equipment protection charge - a fee charged for the protection against loss of the logging tool downhole. If this charge is not paid, the customer is normally liable for the cost of all lost tools. Furthermore, the logging company is not liable for damage to the well.

7) Pressure control equipment - fees may be charged for the installation and use of blow out prevention devices.

8) Equipment rental - mast rental fees are the most common additional fee because either a mast or a rig is usually needed at the site. Costs are usually assessed on a daily rate.

9) High temperature/pressure - fees charged for well environments which exceed the normal temperature and pressure limits established by the logging company. The fees are usually assessed as a per-foot charge.

10) Corrosive fluids - fees charged by the company for corrosive conditions encountered in the well (usually hydrogen sulfide). The fees are usually established on a per-foot basis.

11) Interpretation - fee for log interpretation which is nearly always a separate charge.

Specific costs for these general pricing policy items vary among logging companies. In order to provide a general idea of the costs associated with these items, prices of six major well logging companies were compared. These six companies represent approximately 85 percent of the well logging services performed in the United States. To help ensure continuity among pricing schedules, the "midcontinent" price catalog for each company was consulted. Costs in other regions may vary significantly. Table 6 contains a typical fee schedule for general price items.

In addition to the previously described general costs, log-specific charges are also assessed. Log-specific costs are usually based on a two-item fee schedule, one charge for depth and a second charge for operation. Depth charges are assessed on a per-foot basis with an established minimum charge. This charge is normally assessed based on the deepest reading. Operation charges are also calculated on a per-foot basis with an established minimum charge. These costs are usually based on the actual number of feet in the section logged.

TABLE 6. RESULTS OF SURVEY OF PRICES CHARGED FOR WELL LOGGING SERVICES, "MIDCONTINENT" AREA*

Item	Range of Prices (1982 Dollars)
Service charge	$475 - $1065 per job
Mileage	$2.00 - $2.40 per mile
Crew and equipment	$75 - $150 per day
Specialized crew	$275 - $310 per day
Incomplete operations	**
Equipment protection charge	$35 - $70 per job
Pressure control equipment	$150 - $300 per day
Equipment rental	$290 - $1500 per day
High temperature/pressure	**
Corrosive fluids	**
Interpretation	**
Depth & operation charges	***

*This table was developed as a guide. Prices quoted in this table are subject to change and are based on interpretation of pricing catalog information.

**Due to pricing differences between companies, comparison cannot be made.

***See each specific section for additional costs.

In order to compare costs for specific types of logs between companies, it is necessary to be familiar with applicable trade names for each log. Table 7 provides a listing of seven basic logs which are described in subsequent sections of this report and lists associated trade names for seven major logging companies. Specific cost comparisons for each of these logs is contained within the chapter on each log. The prices are based on those companies which offer the particular logging service.

TABLE 7. INDUSTRY TRADE NAMES FOR BASIC LOGGING SERVICES

Industry Trade Name	Gearhart-Owens Inc.	Schlumberger	Dresser Atlas	Welex	Birdwell	NL McCullough	Dia-Log
Basic Log							
Temperature	Differential Temperature Log (DTL) Temperature Log (TL) Radial Differential Temperature Log (RDT)	High Resolution Temperature (HRT)	Differential Temperature Temperature Log	Precision Temperature Log	Differential Temperature (TLD) Temperature (TL)	Differential/Absolute Temperature Log	Temperature Log Differential Temperature Log
Noise	Borehole Audio Tracer Survey (BATS)	Audio Log	Sonan Log	N/A	N/A	Noise Log	Borehole Sound Survey
Electromagnetic Casing Inspection	N/A	Electromagnetic Thickness Log (ETT) Pipe Analysis Log (PAL)	Electromagnetic Casing Inspection Vertilog Magnelog	N/A	N/A	Casing Inspection Log	N/A
Caliper	Casing Inspection Caliper Log (CICL)	Caliper Log (CAL)	Caliper Log	Caliper Caliper, FoRxo Contact Caliper Log	Caliper Logging (CA3, CA6, CAL, CSG) Micro-Contact Caliper (EMC)	Electronic Caliper Log	Casing Profile Caliper Tubing Profile Caliper
Flowmeter	Spinner Fluid Velocity Survey (SFVS)	Continuous Flowmeter (CFM) Packer Flowmeter (PFM)	Continuous Flowmeter	Fluid Travel Log Spinner Survey	Spinner Log	Spinner Log	Spinner Log
Radioactive Tracer	Radioactive Tracer Log (RTL)	Radioactive Tracer Log (RTL)	Tracer Log Nuclear Flolog	Radioactive Tracer Log	N/A	Nuclear Tracer Log	Tracer Survey
Cement Bond Log	Cement Bond Log (CBL)	Cement Bond Log (CBL) Cement Bond Variable Density (CBL-VDL)	Acoustic Cement Bond Log (ACBL)	Acoustic Cement Bond Log/Micro Seismogram (MSG)	Cement Bond Log (VSD)	Bond Cement/Sonic Seismogram Log	Cement Bond Log

From available information at the time of writing. Subject to change.
N/A = not available.

REFERENCES

Guyod, Hubert and Lemay E. Shane, 1969, Geophysical well logging; Hubert Guyod, Houston, Texas, 256 pp.

Keys, W. Scott and L.M. MacCary, 1971, Application of borehole geophysics to water-resources investigations, book 2, chapter E1; United States Geological Survey, 126 pp.

Labo, J., 1978, A practical introduction to borehole geophysics; Paper presented at the 48th Annual Meeting of the Society of Exploration Geophysicists, San Francisco, California, 44 pp.

Ransom, R.C., 1975, Glossary of terms and expressions used in well logging; Society of Professional Well Log Analysts, Houston, Texas, 74 pp.

Rust, David and G.L. Feather, 1977, Mechanical understanding essential for cased-hole wire-line operations; The Oil and Gas Journal, vol. 75, no. 14, pp. 86-91.

SECTION 8

TEMPERATURE LOGGING

SYNOPSIS

Temperature logs are one of the oldest methods utilized for investigating downhole conditions. In fact, Peacock (1965) suggests that the first physical measurement made in a well, other than depth, was the determination of bottom hole temperature. Early temperature logs were applied only to well conditions known to produce appreciable temperature disturbances, such as cement hydration (Basham and Macune, 1952). However, the heat sensing devices used in temperature probes have been improved radically over the years, and now temperature logs can be used in situations where even minute temperature anomalies must be located.

Three different types of temperature logs are currently available for use in injection wells. A conventional (absolute or gradient) temperature log is a record of the temperature of the fluid surrounding a heat sensor, recorded as a function of depth in a well. The temperature recorded may or may not reflect the temperature of the fluid in the formations surrounding the well. Under static conditions, with no flow in the well or adjacent to the well, the geothermal gradient is measured (Keys and Brown, 1978).

A method of increasing the sensitivity of the data recorded on a conventional temperature log is to supplement these data with a differential temperature log. A differential temperature log is a record of the rate of change of the gradient curve that can be recorded within a wide sensitivity range. This log contains no new information -- it is simply the same data from the gradient curve presented in a different form. The differential temperature log is valuable in that it enables the graphic display of relatively minute temperature changes that may not appear significant on the gradient log; the differential log is highly responsive to the slightest changes in well temperature. Fluid temperatures in the well may be measured with only one sensor, and the rate of change of temperature is obtained electronically or the difference between the two sensors may be measured.

A radial differential temperature (RDT) log measures the variations in temperature in the plane of the casing radius at two points on the inside of the casing wall or between the casing wall and the center of the casing (Cooke, 1978). The RDT log was developed specifically for the purpose of locating areas of channeling behind casing, and is also used to orient perforating guns to penetrate through casing and into channels in the casing - borehole annulus (Cooke and Meyer, 1979).

Temperature logging can be used in a number of ways to evaluate changes that have taken place in and adjacent to a well. The fact that this measurement is dependent on an almost continually changing characteristic makes it different from most other logging measurements. Temperature in a well changes with the geothermal gradient, or the natural increase in the earth's temperature with depth, and may be modified by fluid movement within the well and behind the casing. For this reason, the temperature log is useful in mechanical integrity testing of injection wells.

Temperature surveys have been used to evaluate the following downhole conditions in both production wells and injection wells:

- determining the geothermal gradient,
- locating cement tops by detecting the heat of hydration of curing cement,
- locating points of fluid production in open and cased holes,
- locating tubing and casing leaks, particularly when the leaking fluid is gas,
- detecting channel flow behind casing under some conditions of injection,
- determining injection points and developing an injection profile,
- determining the location of chemical activity during and after acidizing, and
- locating lost circulation zones.

PRINCIPLES

The basis of temperature logging is the fact that the temperature of the earth, and therefore the static temperature in a well, gradually increases with depth. The rate of this change varies due to a number of factors, such as near-surface seasonal changes, circulating ground water and variations in the intrinsic permeability and thermal conductivity of the rocks penetrated by the well. Excluding extremes, geothermal gradients in the United States generally fall within the range of 1.0°F to 1.3°F per 100 feet of depth (Johns, 1966). When the fluid in a wellbore is static, and has been for a long period of time, the temperature in the well is generally regarded as representative of the natural geothermal temperature. Thus, measurement of this temperature reveals the geothermal gradient, provided that there is no vertical flow behind the casing in the casing-borehole annulus. The geothermal gradient is a smooth, linear temperature change.

The reason that variations in the geothermal gradient are observed is that whenever two media at different temperatures are in contact, heat from the higher temperature medium flows to the medium of lower temperature. Given enough time, the plane of contact between the two media will reach the same temperature, or thermal equilibrium. The media may be any combination of solids, liquids or gases. The rate of temperature change that occurs is dependent on the volumes of materials involved, the difference in temperature between the media, the thermal conductivity characteristics of the media, the length of time the heat transfer has been taking place and the presence and rate of fluid movement that may be taking place.

In mechanical integrity testing of an injection well, the last factor is the most important. Any type of fluid movement (liquid, gas or a combination), either outside or inside a well will produce a temperature anomaly. Deviations in the normal geothermal gradient will be created by vertical movement of gases or liquids behind the casing or through leaks in the casing. The temperature of the fluid flowing in a vertical channel outside the casing will normally differ from the geothermal temperature at a given depth in the well. Cooling of gas on expansion, if gas flow is occurring, or because of flow of liquid from a different depth in the well where the geothermal temperature is different will cause the temperature anomalies in a well (Cooke, 1978). If fluid is migrating downward, it is creating an abnormally cool disturbance relative to the natural geothermal gradient. If an upward movement is occurring, then the thermal conditions are reversed and a warm disturbance relative to the natural geothermal gradient is created.

Figure 15 illustrates the hole geometry and the points at which temperatures are measured by the RDT tool and a conventional temperature tool. The radial differential temperature is the difference between Tw_1 and Tw_2, measured at a single depth as temperature sensors contact and rotate around the inside of the casing wall. A conventional temperature log measures Tf, the temperature of the fluid inside the well at different depths as it is lowered in the wellbore. In the case where a channel exists in the cement behind the casing, fluid traveling through the channel heats or cools the casing on that side, causing temperature at Tw_1 to be higher or lower than that at Tw_2 (Cooke, 1978).

EQUIPMENT

Essential to obtaining valid temperature data is a detection system that is sufficiently sensitive to small temperature changes and stable to the degree that accurate readings can be faithfully recorded. The downhole temperature logging tool used for producing

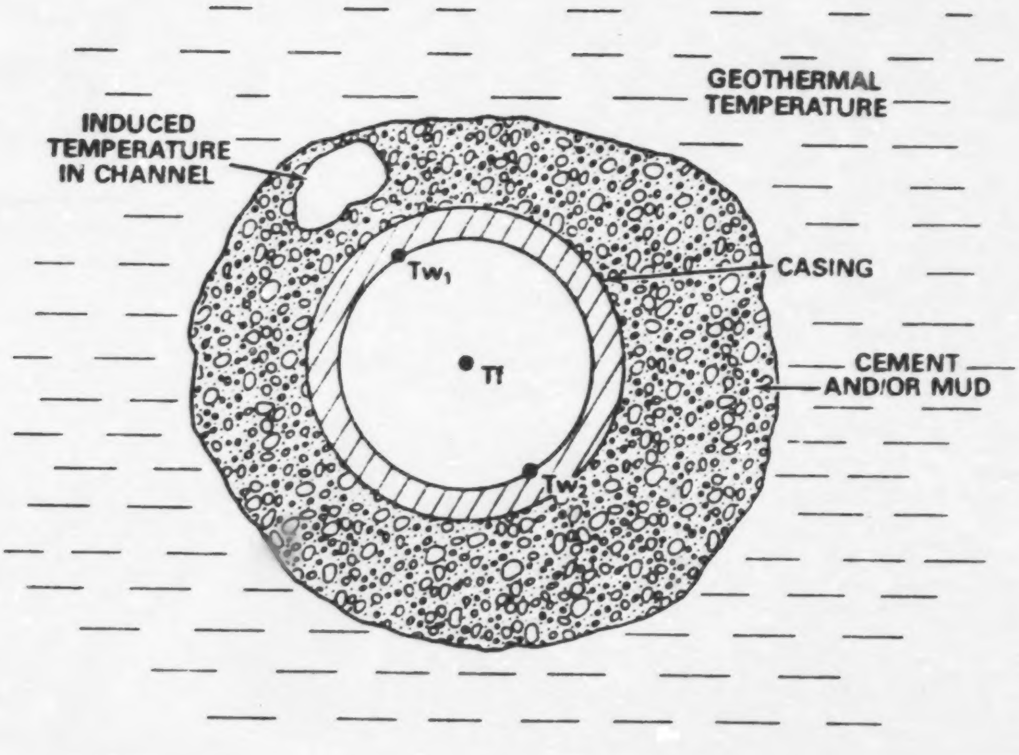


Figure 15. Temperatures in and around a cased and cemented wellbore (Cooke, 1978).

both the gradient log and the differential temperature log employs a heat sensing element to detect temperature changes in the wellbore. The heat sensing element is usually either a thermistor, which converts temperature changes into resistance changes, or a semiconductor element, which converts temperature changes into frequency pulses. Thermistor-type sensors may have an accuracy, repeatability and sensitivity of approximately 0.02°C (Keys and Brown, 1978). The signals produced by the heat sensing element are conveyed to the surface via multiconductor logging cable. Once at the surface, the signals are transformed by electronic surface equipment into voltages proportional to well temperature. The voltages generated are used to produce the log. The log is usually recorded in analog form, however, it is possible to make digital records as well (Keys and Brown, 1978).

The surface equipment used to record the differential temperature log also includes an electronic memory circuit. In the surface unit, the impulse from the downhole tool is fed after a preselected time into a comparison circuit, which is also impressed with the impulse generated at that time. The difference in temperature detected at the two time intervals is recorded as the differential temperature. The gradient temperature log is recorded on a separate circuit.

Typical downhole tools range from 7 to 8 1/2 feet long and 1 1/2 to 1 11/16 inches in diameter, for use in wells of 1 11/16 to 1 25/32 inches minimum diameter. Available tools are constructed to withstand downhole temperatures of from 325°F to 400°F and pressures of 15,000 to 20,000 psi. The tool employs centralizers to keep it centered in the borehole.

Components of the RDT downhole logging tool are shown in Figure 16. The temperature sensors, which are similar to those used in a conventional temperature tool, are located on arms 180° apart, that are extended and retracted by an electric motor. The contact diameter of the extended arms is adjusted so they exert slight pressure to maintain contact between the temperature sensors and the casing wall (Cooke, 1978). A motor near the top of the tool rotates the tool at a speed of one revolution every 2 1/2 minutes (Cooke and Meyer, 1979). The outside diameter of the tool is 1 11/16 inches; the length of the tool, a collar locator and two centralizers is 12 feet. The tool can be run through tubing on a conventional logging cable and used in any size casing from 2 3/8 inches to 9 5/8 inches; a tool has been modified for use in 13 3/8 inch casing. An anchor spring at the top of the tool prevents the entire tool from turning as the sensor arms rotate (Cooke, 1978). The difference in temperature between the two sensors can be measured with high sensitivity -- in the range of 0.005°F (Cooke and Meyer, 1979).

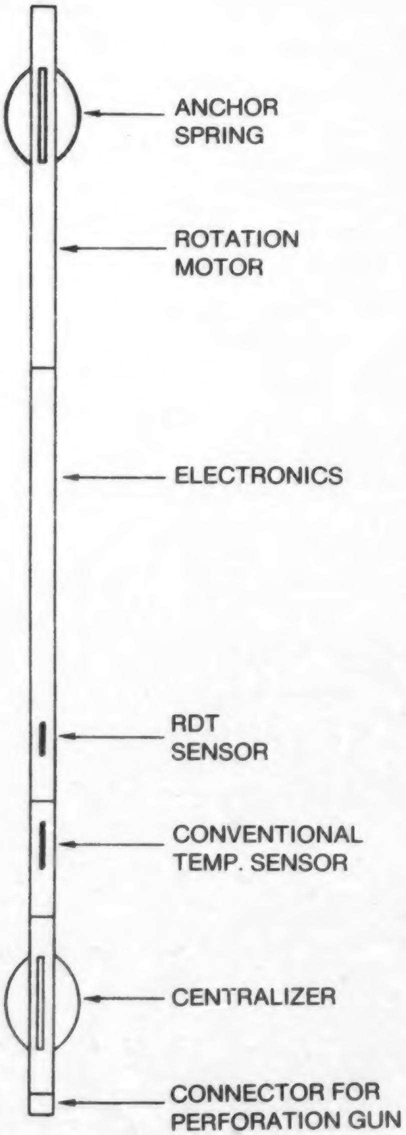


Figure 16. Schematic of RDT logging tool (Cooke, 1978).

PROCEDURES

For the purposes of mechanical integrity testing, the primary objective for running a temperature log in an injection well is to determine whether there are any leaks in the casing or tubing or whether there is flow occurring through channels in the casing - borehole annulus. This is customarily accomplished by stopping injection and shutting the well in for a period of time to allow the well to stabilize and reach near-normal temperature prior to logging. If a well is logged too soon after being shut in, the casing and tubing will not have dissipated their heat and little or no character will be found on the temperature log (Kading and Hutchins, 1969) (Figure 17). Timing of the temperature log with respect to when it is run after the well has been shut in is very important, because the log can be run too soon or too late to detect minute temperature anomalies caused by mechanical integrity problems. The amount of time required for the well to be shut in depends on a number of factors, including well construction and injection operation details. Usually 24 to 48 hours are needed for the well to stabilize, but large diameter boreholes will require longer stabilization periods than small diameter wells (Kading and Hutchins, 1969). Ideally, the borehole temperature in a shut-in well reflects the distribution of temperature in the formations adjacent to the well.

Because of the critical nature of the timing of the logging operation, a sequence of temperature profiles is usually recorded as the borehole temperature returns to the natural geothermal temperature (Witterholt and Tixier, 1972). Portions of the temperature profile that deviate from the smooth geothermal curve (anomalies) provide the information for locating injected fluid -- its points of exit from the casing, whether known perforations or unexpected casing leaks, and/or its flow in channels behind the casing.

In wells completed with tubing and packer, it may be necessary to remove the tubing in order to properly detect or locate leaks in the casing or fluid movement in channels behind the casing. Temperature anomalies may not be adequately transmitted through the tubing-casing annulus, thus it may be difficult to recognize well problems if the log is run through the tubing.

The downhole temperature tool is always calibrated prior to being run in the well. In recording the conventional temperature log, logging is accomplished going downhole to avoid temperature disturbances caused by the motion of the tool in the well. Temperatures within the well are detected by the downhole tool and a signal representing these temperatures is transmitted to the surface, where it is recorded versus depth. Logging speed varies from about 10 to 40 feet per minute depending upon well conditions and probe response. Continuous logs, made at logging speeds of 25 feet per

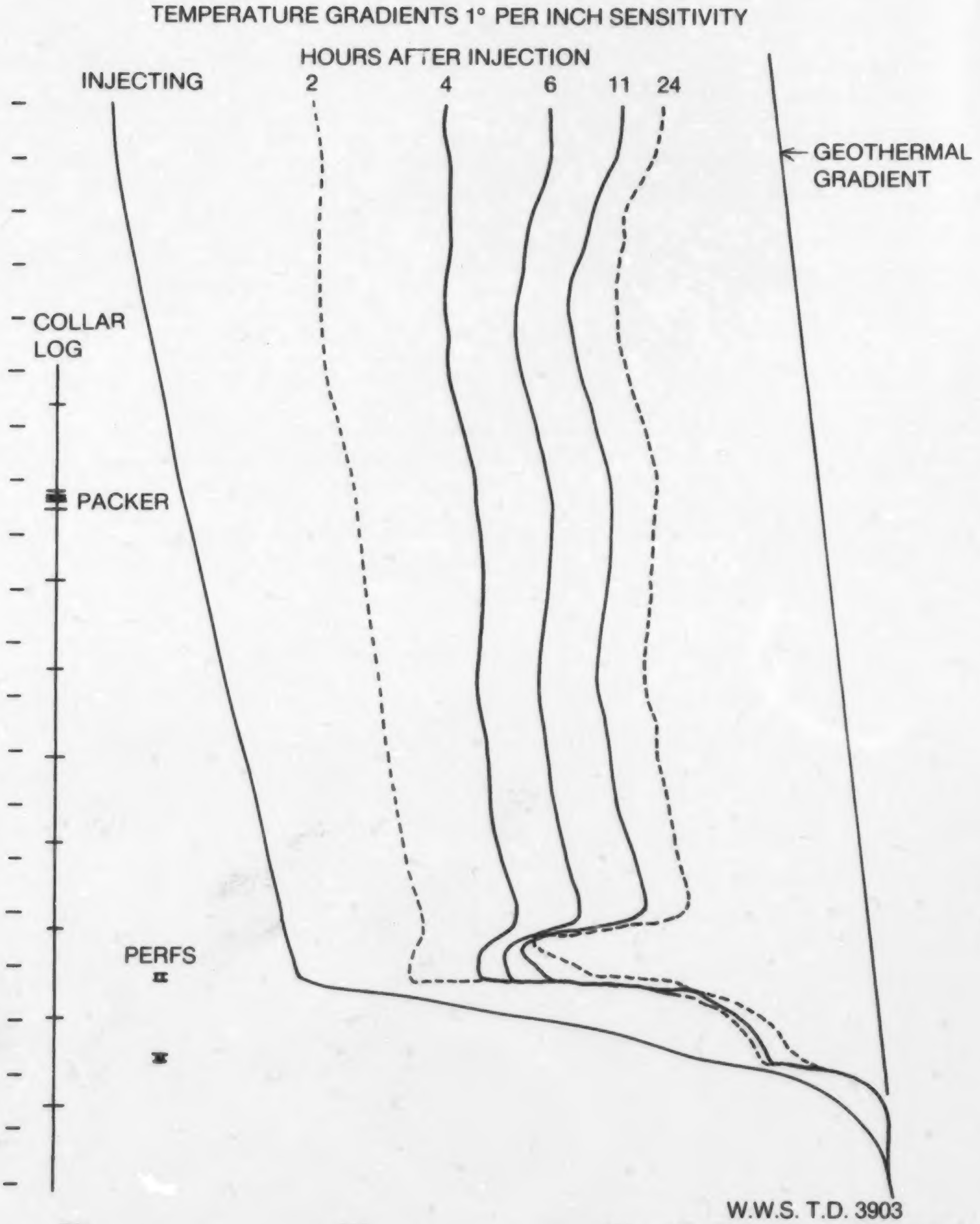


Figure 17. Gradient temperature logs run at various times after well is shut in (Kading and Hutchins, 1969).

minute, have been compared with point-by-point measurements, and discrepancies of no more than 0.03°C were found (Keys and Brown, 1978).

Kading and Hutchins (1969) describe a procedure for locating gas channeling behind casing utilizing a gradient temperature log. When attempting to locate gas entry, the most successful procedure is to flow the well for a period of twelve hours or more before starting the surveys. The first survey should then be recorded under a stable flow condition. Gas entry into a wellbore is determined by a cooling at the gas entry point or by a temperature increase just below the gas entry point. Note that a gas source may not be evident on the flowing run if gas is channeling from above the point of entry into the wellbore. The gas flowing up the casing and past the temperature instrument will mask the anomaly at the point of entry.

The next step is to shut in the well and immediately run a survey over the area of interest. Static or near static conditions will remove the masking effect of the flowing gas and also allow the small temperature changes caused by channeling gas to be detectable adjacent to their point of occurrence. Transient temperature anomalies may be recorded; therefore, more than one static survey should always be run. These spurious temperature changes will usually move uphole and be recorded at varying depths, so temperature changes at constant depths indicate true gas movement. Figure 18 is a gas entry log with stable flow and static runs which shows a gas entry behind the casing channeling around the casing shoe.

The temperature survey can only be used in a qualitative sense for gas entry because of the factors which cause this temperature change. A large volume of gas moving through an unrestricted area with little temperature drop, will log a small temperature change compared to a small volume of gas having a large pressure drop. The high pressure drop low volume entry with its large temperature change will mask adjacent significant gas entries. This is one of the reasons that shut-in surveys sometimes must be run after flowing surveys (Kading and Hutchins, 1969).

The differential temperature log is recorded simultaneously with the gradient log from the same downhole tool. It is a continuous measurement, and at a particular point on the log gives the difference in the temperature at one depth and a preselected depth uphole. The subsurface temperature data transmitted to the surface are fed into a memory storage and differential computer. The computer stores and continuously compares temperature measurements between two subsurface points. The two points, or spacings, are selected at the surface based on the logging speed. Proper selection of the variable spacing is dependent on the desired resolution of the slope changes. Differential temperature measurements, at the selected spacings chosen to be the most suitable to individual well conditions, are obtained to provide maximum benefits from the log. Differential temperature logs may also be run using two sensors.

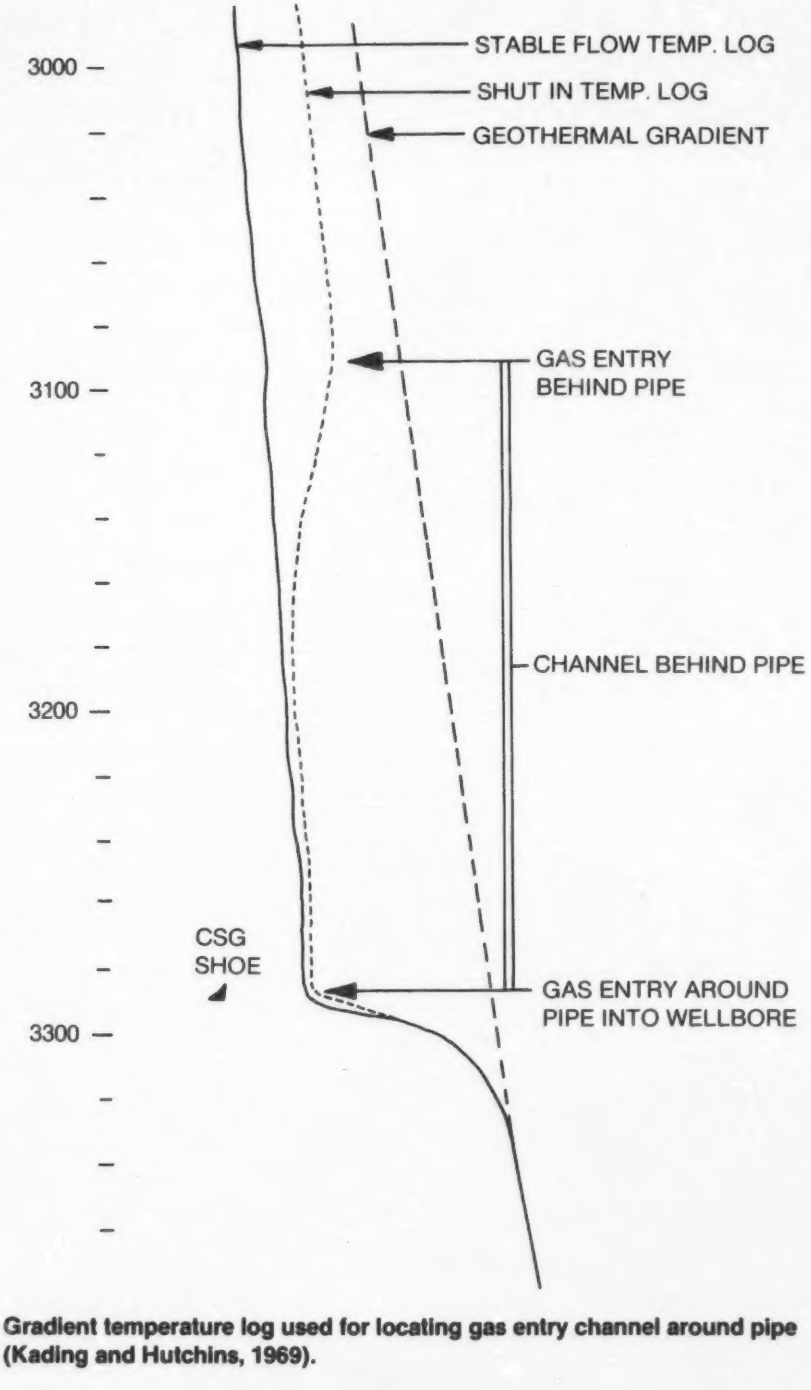


Figure 18. Gradient temperature log used for locating gas entry channel around pipe (Kading and Hutchins, 1969).

The procedure for running a radial differential temperature log differs significantly from that for either a conventional or differential temperature log. The RDT log is typically utilized after a downhole problem (especially a channel behind the casing) is already suspected. The RDT tool is lowered to depths in a well where a channel is suspected, the arms containing temperature sensors are extended and the motor is engaged, allowing the tool to make one or more revolutions. The temperature sensors contact the casing so that the thermal properties and movement of fluid in the well have a lesser effect on the measurements (Cooke and Meyer, 1979). The log is made, the sensor arms are retracted and the tool is moved to another depth, where the procedure is repeated. As many measurements can be made as needed at different depths in order to delineate a channel (Cooke, 1978).

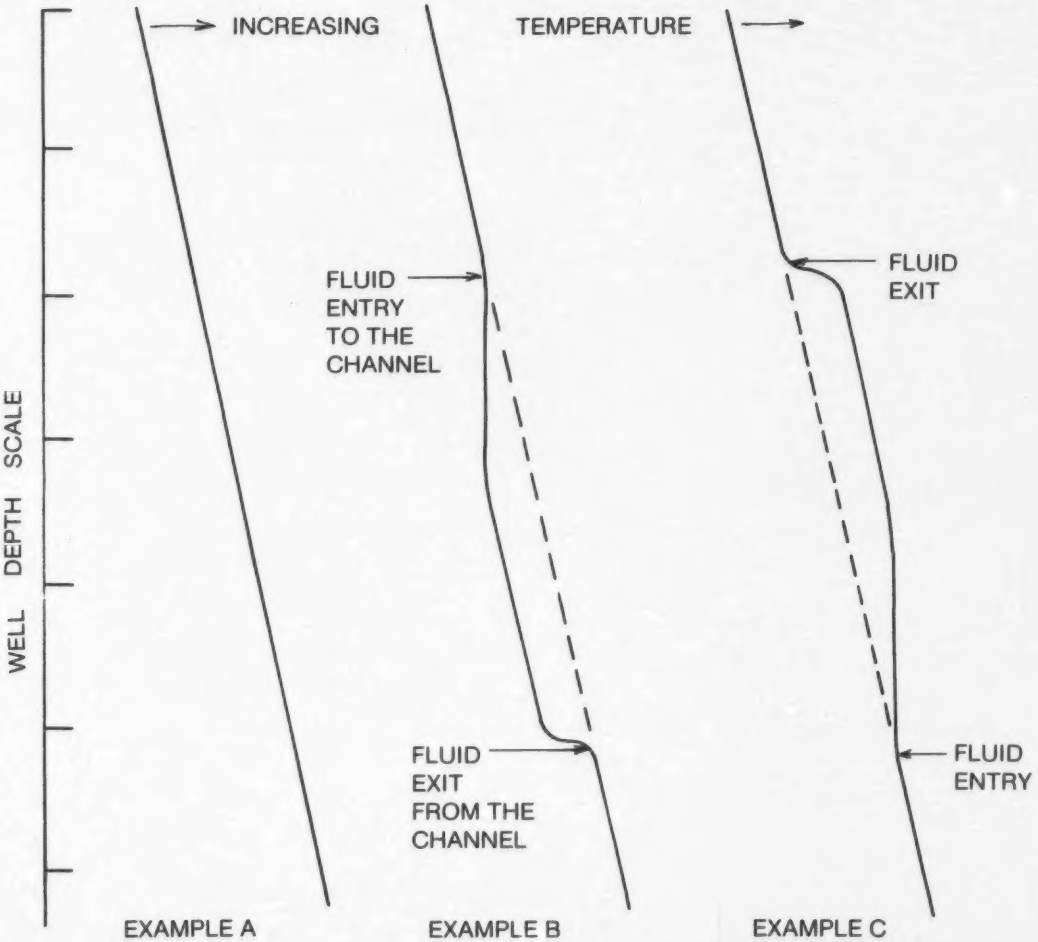
Rotation of the RDT tool produces a signal that is used to mark the edge of the chart paper. The marks are omitted in one interval of each revolution so that the end of the revolution can be easily located on the chart. The curve is normally reproduced by the recorder on each revolution (Cooke, 1978).

Cooke (1978) and Cooke and Meyer (1979) indicate that greater differences in temperature between fluid flowing in a channel behind the casing and the geothermal temperature at a given depth can be obtained by injecting fluid at the surface into open perforations to cool the channel. This technique is particularly useful if the temperature of the channel relative to the geothermal temperature is not known and has been successful in locating channels both above and below perforations. The temperature of fluid entering perforations can be monitored during injection by using a conventional temperature tool. The RDT tool can then be run in the well and used to detect the channel. With this technique, temperature differences as great as 3°F have been measured on opposite sides of well casing (Cooke and Meyer, 1979). Temperature differences from flow of subsurface fluids between zones are much smaller -- often in the range of 0.005°F to 0.05°F (Cooke, 1978).

INTERPRETATION

Because of the large number of mechanical configurations of tubing, casing, packers and injection conditions in injection wells, there is an almost unlimited variety of responses that could be obtained with a temperature survey. However, it is possible to generalize the types of deflections a temperature log will display in response to fluid leaks and movement in channels behind casing. Figure 19 shows common log responses to the natural geothermal gradient, and two conditions of fluid flowing behind casings.

On a temperature log, deflections from the geothermal gradient may be due to reasons other than casing leaks or fluid movement behind



EXAMPLE A

NATURAL GEOTHERMAL GRADIENT AS MEASURED IN A STABLE WELL

EXAMPLE B

TEMPERATURE ANOMALY SUPERIMPOSED ON GEOTHERMAL GRADIENT INDICATIVE OF DOWNWARD FLOW THROUGH A CHANNEL BEHIND THE WELL CASING

EXAMPLE C

TEMPERATURE ANOMALY SUPERIMPOSED ON GEOTHERMAL GRADIENT INDICATIVE OF UPWARD FLOW THROUGH A CHANNEL BEHIND THE WELL CASING

Figure 19. Examples of gradient temperature logs showing the natural geothermal gradient and anomalies caused by flow through a channel behind the well casing.

casing. Local variations in thermal conductivity or intrinsic permeability of rocks penetrated by the well and the presence of zones of ground-water circulation could significantly alter the expected gradient. Practically, a temperature survey at a particular time is compared with similar data from a different time period. By noting the difference in the two sets of data, conclusions are drawn to explain the reason for these differences. Since it is unlikely that all of the possible variables encountered in a well will be known quantitatively, it is difficult to arrive at precise conclusions from temperature surveys. Supplementary data, including information on local geology and any other available well logs, should always be considered when available.

Sharp definition of temperature interfaces with a gradient log is improbable unless the difference in temperatures is extreme; slight changes go unnoticed unless recording sensitivity is high. In all applications of the gradient log, there are occasions when the recorded temperature anomalies are too small to be interpreted with certainty. The differential temperature log, because of its ability to detect and amplify minute anomalies, is effective in these situations (Peacock, 1965). The anomalies on both the gradient and differential temperature log are often quite confusing, and sometimes do not represent the downhole situation. This is particularly true when the cross-sectional area of, for example, a channel behind the casing compared to the volume of the well is very small (Pennebaker and Woody, 1977).

The differential temperature log graphically indicates changes in temperature gradient. The log plots the rate of change in temperature as well as the magnitude of the difference. Increases in temperature are plotted to the right of an axis line on the log, while decreases are plotted to the left. Anomalies show up as distinctly large deviations (either increases or decreases) from the normal gradient.

One of the biggest pitfalls in interpreting any temperature log is the tendency to select the wrong scale for recording the log. Depth and temperature scales selected are commonly so large that subtle temperature changes are often lost or confused with normal variations in temperature caused by, for example, different rates of cooling or heating in shale or sand intervals (Pennebaker and Woody, 1977).

As Basham and Macune (1952) point out, the chief value of differential temperature measurement lies in the fact that a difference between two factors can be measured with a scale of values best suited to that difference; a scale that might be cumbersome or impractical if applied to the factors themselves. When it is known that all factors will be nearly equal in value, and therefore the differences consistently small, it is possible to select a scale that will permit very accurate measurement of the differences.

As with other logs, another type of log should be compared to the gradient log or differential temperature log so that proper correlations can be made with perforated zones, packer settings and casing collars. This is particularly true in injection wells that have a dual completion. During a shut-in period, fluid from one zone may migrate into the well and travel via the casing to another zone of lower hydrostatic pressure. When this occurs, the borehole is artificially heated or cooled and interpretation is hampered. Without another log for correlation purposes, the interpretations from either a gradient log or a differential temperature log could be misleading.

COST

The cost of performing a temperature log is dependent upon the many general pricing variables as outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Tables 8 and 9. Refer to Table 7 for a listing of companies surveyed which perform this service.

TABLE 8. TYPICAL DEPTH AND LOGGING CHARGES FOR STANDARD TEMPERATURE LOGGING

Depth Charge	Low	High
per foot	$0.20	$0.29
minimum	$400	$580
Logging Charge	**Low**	**High**
per foot	$0.20	$0.29
minimum	$400	$580

TABLE 9. TYPICAL DEPTH AND LOGGING CHARGES FOR DIFFERENTIAL TEMPERATURE LOGGING

Depth Charge	Low	High
per foot	$0.22	$0.33
minimum	$450	$990
Logging Charge	**Low**	**High**
per foot	$0.21	$0.33
minimum	$400	$950

Refer to Table 7 for a listing of companies surveyed which perform this service.

At the time of writing this report, only one firm offered the Radial Differential Temperature log. Their costs are explained in Table 10.

TABLE 10. TYPICAL CHARGES ASSOCIATED WITH RADIAL DIFFERENTIAL TEMPERATURE LOGGING

Depth Charge per foot	$ .30	Min. $ 600.00	
Each Station Reading	$50.00	Min. $ 400.00	
Temperature Log - Operation Charge	$ .18	Min. $ 360.00	
Tool Used to Read Temp.	No Charge		
Each Jet Charge Used	$45.00	Min. $ 540.00	
Royalty Charge:			
Per Well (Land Operation), 6,000' or less			$148.20
Per Well (Land Operation), greater than 6,000'			$296.40

ADVANTAGES AND DISADVANTAGES

Perhaps the primary advantage of temperature logging is that a properly run and interpreted temperature log can indicate not only tubing and/or casing leaks, but also channeling in the cement sheath behind the casing of an injection well. Differential temperature logs are very useful in this regard; the differential temperature can be known with much greater accuracy than the absolute temperature. RDT logs are specifically run for the purpose of locating channeling behind casing. The RDT log may define not only the interval of channeling behind casing, but also the orientation of the channel (Cooke, 1979). This would facilitate later remedial action.

Additionally, the technology of temperature logging has seen a number of significant advances over the years; the equipment now utilized is able to detect very small changes in temperature. Temperature log interpretation has also become more sophisticated with the advent of digitized logs and computer matching techniques. However, in spite of all of the literature on field examples and the advances in equipment and simplified interpretation procedures, temperature logging continues to be an art rather than an exact science (Witterholt and Tixier, 1972). Utilizing a temperature log as the sole means for making important decisions regarding a well is not advisable; other logs must commonly be used to assist in the interpretation of downhole situations.

A significant disadvantage of utilizing temperature logs in mechanical integrity testing relates to the fact that the well must be taken out of service for anywhere from 24 to 48 hours or more to allow the well to reach thermal stability. The injection tubing and packer may also have to be removed during the logging process and then replaced. This may significantly affect the schedule of operation of production wells relying on the injection well to dispose of salt water.

Large diameter wells may not benefit as much from a temperature log as smaller diameter wells due to thermal attenuation that occurs between temperature anomalies and the logging probe which is normally centered in the well. The radial differential temperature log partly eliminates the problem because the temperature sensors actually come in contact with the casing. However, the RDT tool is limited to use in casings 13 3/8 inches in diameter or smaller.

EXAMPLES

A conventional use of gradient temperature surveys is shown by Figure 20. This illustrates leaks in two gas wells equipped with tubing and packer. Both wells had been produced at moderate rates for some time, then shut-in. Gas expanding through the leaks reduced the temperature several degrees as shown. The leaks were approximately located in reconnaissance surveys, then pinpointed by stops made at 25- to 50-foot intervals, as the figure indicates. In subsequent tubing repair work, the leaks were found to be very close to the points indicated (Pierce, et. al., 1966).

In Figure 21, the gradient temperature log (left-hand side) shows gas moving from the top of a channel behind the casing at 2320' and migrating downward to the top of the perforations at 2380'. In both cases, there is a deflection to the left at the problem, indicating that the flow through the channel is cooling the casing relative to the natural geothermal temperature. A squeeze cement operation above the perforations successfully sealed the channel (Peacock, 1965).

Detection of a casing leak, shown in Figure 22, was accomplished by making all logging runs with the well shut in. The first log run, the gradient temperature log (left) indicated a leak at 3420'. Two differential temperature logs run at different sensitivity settings confirmed the leak at same depth (Peacock, 1965).

The well depicted on the log in Figure 23 (from Cooke and Meyer, 1979) originally fed in a small amount of gas and 0.5 barrels per hour (bbl/hr) of water when the fluid level was swabbed to just above the perforations. The well was then acidized with 1000 gal of acid (400 gal mud acid with preflush and after flush of hydrochloric acid), after which it flowed 100% salt water at a rate of 12 bbl/hr.

At this point, the RDT log was used to detect a channel above the perforations by injection of water into the well. Figure 23 shows the location of the RDT tool when water pumping began. The wellbore was originally full of water. The temperature log showed that cooling appeared to exist above the perforations. As can be seen in the RDT

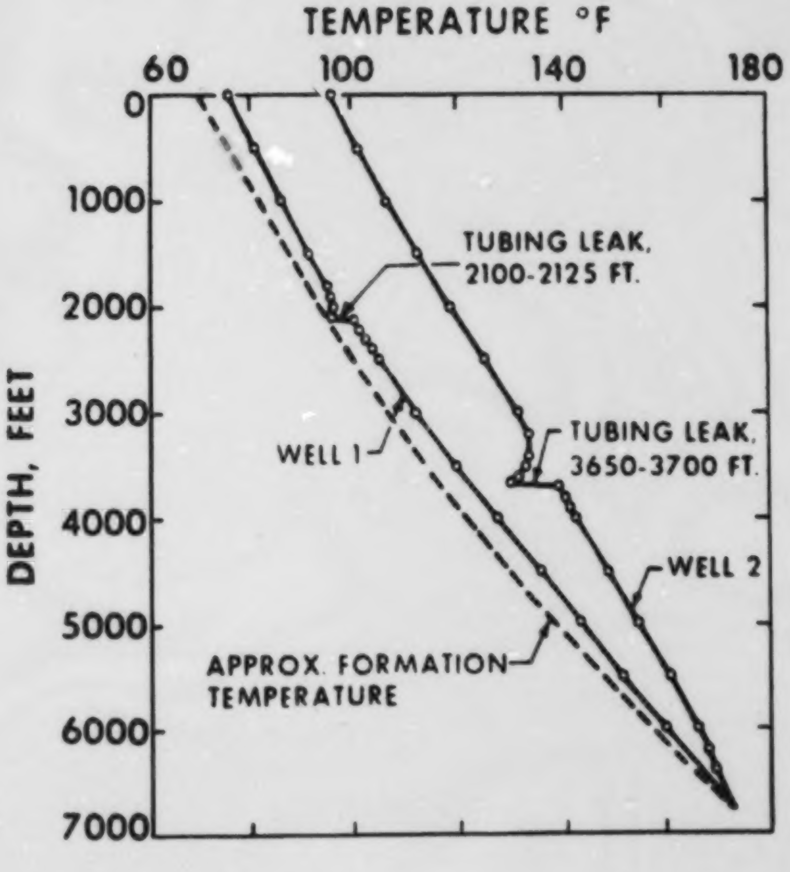


Figure 20. A gradient temperature log used to locate a small gas leak in tubing (Pierce et al., 1966).

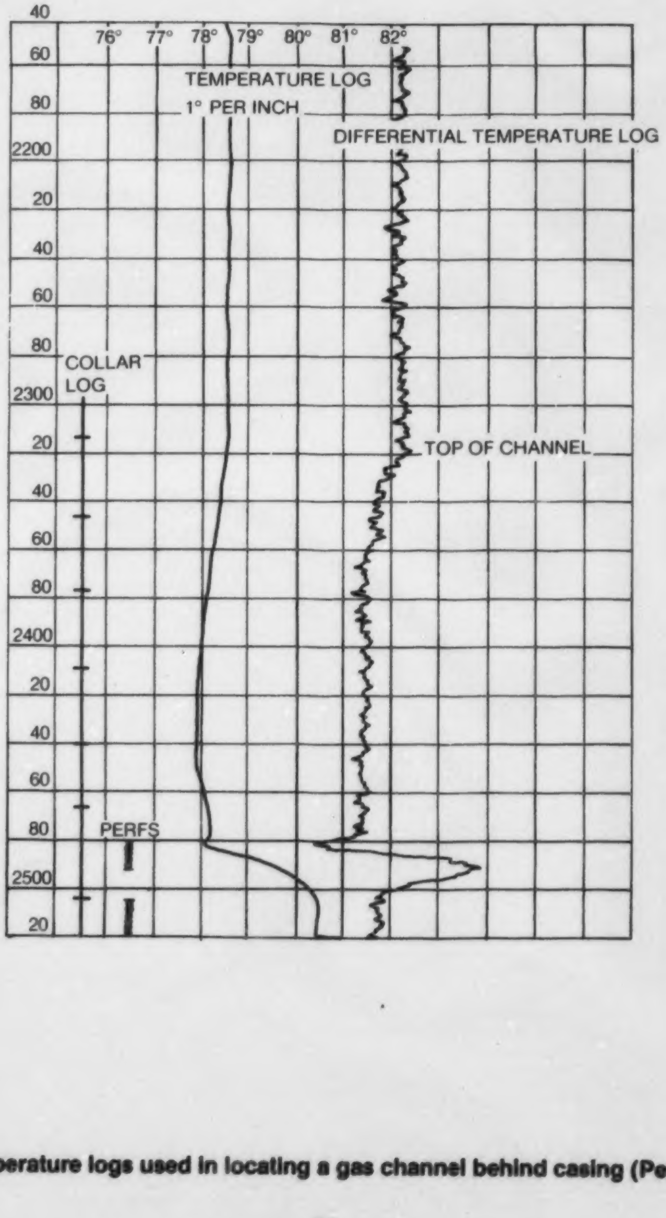


Figure 21. Temperature logs used in locating a gas channel behind casing (Peacock, 1965).

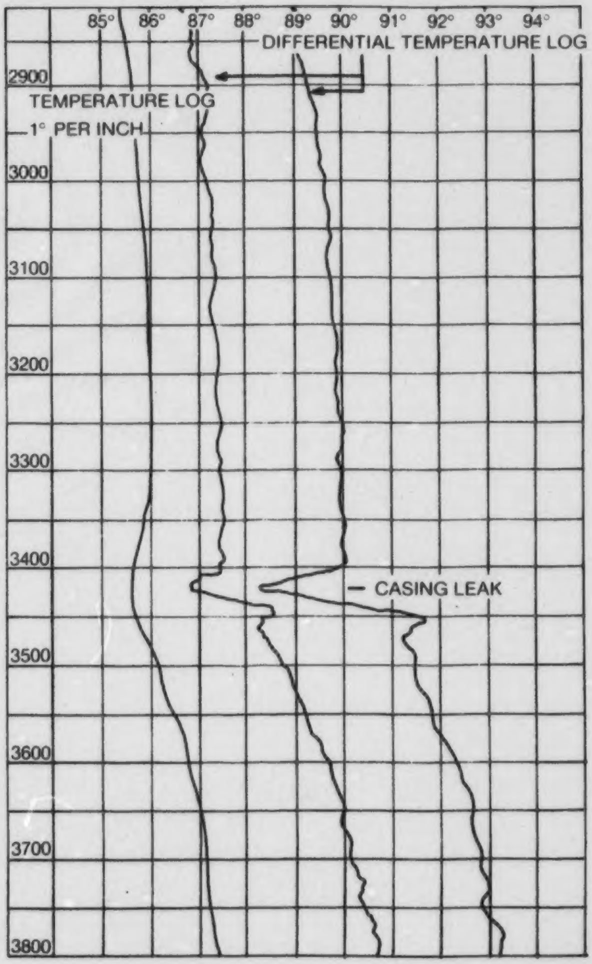


Figure 22. Temperature logs used in locating a casing leak (Peacock, 1965).

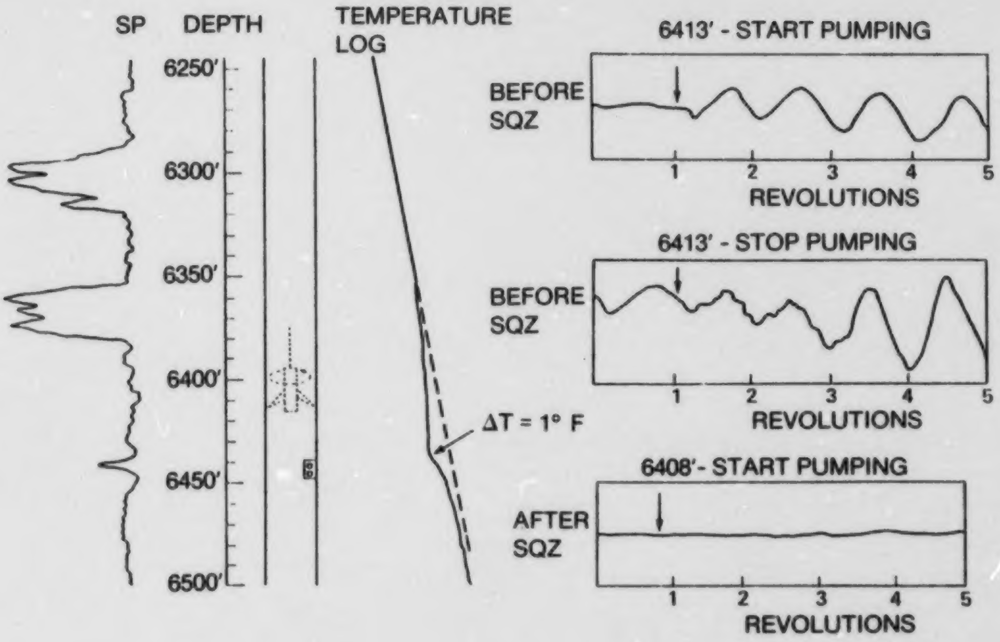


Figure 23. RDT scans and temperature log in a well, showing channel to potential gas zone before squeeze and no channel after squeeze (Cooke and Meyer, 1979).

plots on the right side of the figure, no signal was observed above the perforations before water was pumped into the well. Very soon after water injection began, the RDT signal appeared. This signal repeated for a period of 30 minutes, each time with the peak at the same angle of rotation, as water was pumped into the well at a rate of 0.5 BPM. Water injection was then stopped. The next RDT curve shows that the amplitude of the signal increased slightly as the water pumping ceased. The well was perforated in the direction of the lower temperature.

This well was later squeeze cemented, but the zone produced negligible amounts of gas. The RDT log was then rerun in the well, using the same procedure to determine if a channel existed. As shown on the figure, no signal was observed after the squeeze job, indicating that the channel had been repaired, but the perforated zone was not productive.

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SECTION 9

NOISE LOGGING

SYNOPSIS

Noise logging was first used in 1955 to detect leaks in casing strings of producing oil and gas wells. Enright (1955) described a procedure for utilizing a downhole microphone to locate noise peaks associated with the point of origin of a leak in the casing. Since that time, several other authors have described the use of noise-logging techniques to search for fluid movement within channels in the cement in the casing-borehole annulus. Robinson (1976a) describes five applications in which the noise logging technique has proven useful:

1) existing production (or injection) wells with cemented casing having channels or communication behind the casing;

2) new wells with cemented casing in which channels develop before perforating;

3) wells that develop underground crossflow or "blowouts";

4) wells losing injected gas or fluid; and

5) determining relative flow rates from perforated zones.

The noise log is a trace of the noise intensity in the well versus depth. The noise logging tool, which detects the acoustic (sound) energy generated by the turbulent flow of fluids moving through restrictions, can be utilized in virtually any downhole condition, whether the well is filled with liquid or gas. The sound energy created by fluid movements can be detected through the cement, the casing, the annulus fluids, and the tubing. Sound energy between 200 Hz and 6000 Hz is picked up by the noise logging tool and converted to an electrical signal that is amplified and transmitted to the surface to an electronic recording device. The surface equipment further amplifies the signal and splits it into several frequencies. A determination of the type of flow occurring at a noise source can be made from an analysis of the sound frequency spectrum. Volume of flow can be calculated from the sound amplitude.

PRINCIPLES

Any composition of fluid (liquid or gas) flowing through restrictions (either leaks in a well casing, or in channels behind the casing of a well) generates a complex group of distinctive audible sound frequencies between 200 Hz and 6000 Hz. Turbulence generated by fluid moving from points of low hydraulic head to points of higher hydraulic head creates a sound field within the well casing. The intensity of this sound field is greater than the ambient (background) noise level in the wellbore. The sound energy which is generated by fluids in motion is transmitted through the various well components (cement, casing, annulus fluid, and tubing) and can be detected with a noise logging tool. When the sound energy from the moving fluids is detected by the tool, the mechanical vibrations are transformed to electrical signals having an alternating frequency wave form. The noise log signal wave form produced by the moving fluid is a composite of many frequencies, each of which has an intensity that varies with time. Selection of the proper time constant gives quantitative average values of the wave-form amplitude. This amplitude, as plotted on the noise log, is expressed in AC millivolts (mv) (NL McCullough Inc., no date).

The noise log records two kinds of information about downhole noise: an amplitude profile and a frequency structure. The amplitude profile indicates the presence or absence of fluid movement and allows for the location of the noise source. The frequency structure provides a means of determining whether the flow occurring is single-phase or dual-phase flow and also yields information about pressure differentials (Pennebaker and Woody, 1977).

The amount of noise generated by fluid movement in a well at any point along its path is proportional to the volume of flow and to the pressure differential acting on the flow at this point. In the case of a leak in the casing, the greatest pressure differential occurs at the source of the flow (i.e. a hole in the casing). In the case of flow in a channel behind the casing, pressure differentials may occur at the source of the flow (i.e. a high pressure zone), at restrictions along the flow path (i.e. in a channel in the cement sheath), and at the sink of the flow. These places where flow occurs across a pressure differential are displayed as amplitude peaks on the noise log (NL McCullough, no date).

EQUIPMENT

The noise logging sonde contains a transducer which can be as small as 1 inch in outside diameter, thus enabling the device to be used in casing or tubing as small as 1 1/2 inches inside diameter. The tool is small enough that it can even be lowered down the annulus between the tubing and the casing, provided the annulus is at least two inches wide and that the tubing is centered within the casing.

Several different tools are described in the literature and used in practice in the oil industry. McKinley et al. (1973) describe a tool 3 feet long which consists of a piezoelectric crystal detector in its lowermost section and an amplifier in its uppermost section. This tool, which is encased in stainless steel, is able to withstand corrosion as well as maximum operating pressures up to 14,000 psi and temperatures up to 325°F (transistorized amplifier model) or 500°F (vacuum-tube amplifier model).

Robinson (1976b) describes a longer tool (6 feet in length) in which the bottom third consists of an oil-filled, pressure-compensated piezoelectric detector (Figure 24), and the middle third of the sonde is an amplifier. Amplifier gain ranges from 200 to 2000 so that both low flow rates (as low as 100 cubic feet per day of gas) as well as high flow rates (up to several million cubic feet per day) can be detected without having to manually adjust the gain. The upper two feet of the tool is a magnetic collar locator which is used to correlate the noise log depth with the log of any other tool that has a similar device. The maximum operating pressure and temperature of this tool are 22,000 psi and 350°F respectively.

Britt (1976) describes another noise logging tool 1 11/16" in outside diameter, 48" long, with a 15,000 psi pressure and 350°F temperature rating. As with the other tools, the downhole device is simply a very sensitive microphone with a downhole amplifier. The microphone is designed to respond to sound which originates in any direction around the well and therefore has no directional properties. The tool is not equipped with centralizers.

Each tool described above is sensitive enough to detect significant noise from within a tubing or casing at a distance of 200 feet above or below the source. Even when close to the source, distinct noise level changes can be detected in as little as six inches, the length of a typical sensing element (Pennebaker and Woody, 1977).

The noise logging sonde is run downhole on a single conductor cable, which transmits the signal generated and amplified by the sonde to the surface. There it is received by an electronic recording unit in which the noise signal output from the sonde is further amplified (Figure 25). As the signal is received, it may also be heard by the operator through a speaker or high-fidelity headphones.

Within the surface recording unit the noise signal is, after amplification, divided into four separate frequencies. Four separate band pass filters eliminate different parts of the noise spectrum, resulting in the recording of noise levels above four separate frequencies: 200 Hz; 600 Hz; 1000 Hz; and 2000 Hz. After the four frequency levels are displayed, the AC voltage from each of the four noise amplitudes enters an analog to digital converter and four digital voltmeters register the four peak-to-peak voltage values.

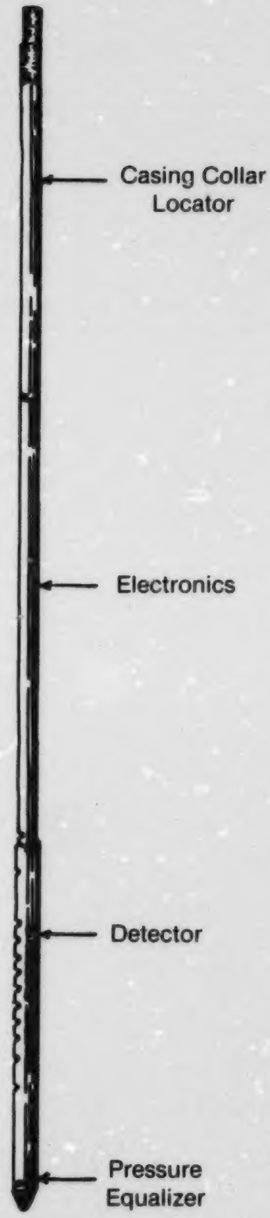


Figure 24. Typical noise logging tool (Robinson, 1976b).

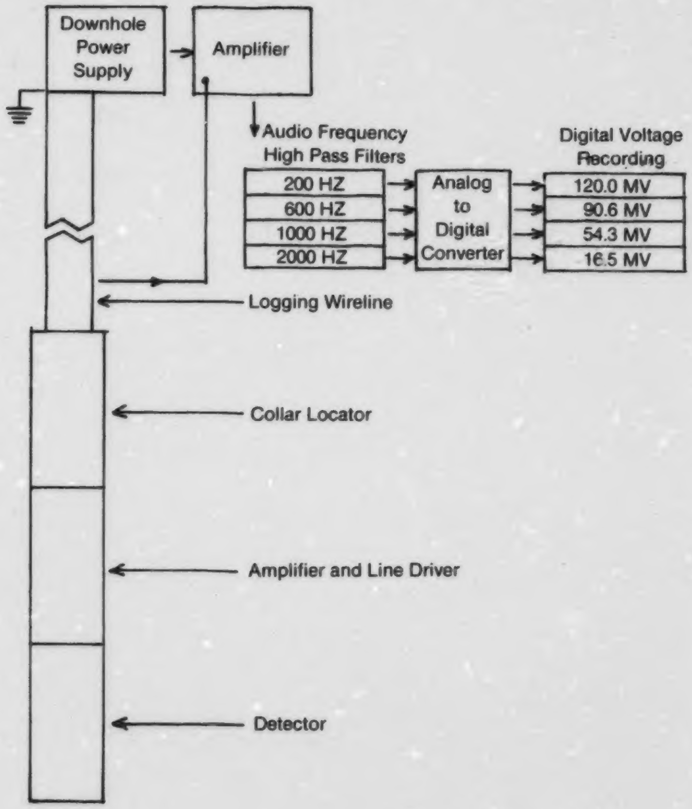


Figure 25. Block diagram of noise logging system (N.L. McCullough, no date).

These four voltage values are recorded at each depth on a data sheet. After all data are recorded, the four noise levels are plotted versus depth on semilog graph paper, thus producing a noise log with four separate curves. Observing the amplitude which is not filtered out by each filter indicates the spectrum of the noise generated by a noise source. These amplitudes are measured at each logging interval.

PROCEDURES

The standard method of producing the noise log is to lower the tool down the hole in a non-recording mode and raise it gradually, recording on the trip back up the well. Because the sonde is sensitive to any noise that can be heard in a well, the noise that is generated by the movement of both the tool and the wireline downhole must be eliminated, or it may mask out the noise produced by fluid movement. Thus, the noise log is usually made with the logging sonde in a stationary position, and the survey is performed on a station-by-station basis. Also, the well must be completely shut in to ensure that all surface leaks through wellhead connections (i.e. valves and fittings) are eliminated, since any noise generated at the wellhead may be transmitted downhole.

With regard to selecting the intervals of logging stations used in the noise survey, generally recording stops are made every 200 feet to establish a background level and to listen for sound from any potential noise sources. Pennebaker and Woody (1977) and Robinson (1976a) suggest that intervals of 500 to 1000 feet may be adequate to establish background conditions in some situations.

If a noise should be detected, progressively smaller intervals are used to pinpoint the source of the noise. Intervals of 25 to 50 feet may be used upon first recognition of a noise source; 5 to 15 foot intervals are usually adequate to close in on a source; and 1 to 2 foot intervals are generally used to pinpoint the problem area. Closely spaced readings may also be appropriate at all casing seats and through any other changes in well construction details (Pennebaker and Woody, 1977).

At each downhole station, the noise logging sonde is stopped until the stabilized noise levels above the four standard frequencies are recorded and plotted on the log. This operation may require up to three minutes for each stop (McKinley et al., 1973). Britt (1976) maintains that the typical time for extraneous noise to die out in a well is 40 to 60 seconds -- this can be determined by listening to the well sounds with the headphones. Time required to read and tabulate the various frequency cuts ranges from about 30 seconds (Britt, 1976) to only about 15-20 seconds per stop (Pennebaker and Woody, 1977). This method of log operation is unlike that used for other logs, which result in a continuous record of the measured parameter versus depth.

Unless a noise source is detected, even with the discontinuous nature of the noise logging operation, it is possible to achieve almost the same average speed as with "normal" continuous logging and still collect high-precision data. Average logging speeds of from 25 to 35 feet per minute are reported for detailed logging runs in which stations 20 feet apart are used (Britt, 1976). However, because the tool must be stopped and the recording/plotting operation performed at smaller intervals to pinpoint a noise source, this procedure can become very time consuming.

INTERPRETATION

The noise log allows for a simple form of frequency analysis by recording four separate noise amplitude curves. Within the surface electronic equipment, a series of band pass filters, which eliminate all audio frequencies below selected frequencies and pass all frequencies above those selected, separates the frequency spectrum of the sound for analysis of the individual amplitudes contained in each of four bands: 200 Hz; 600 Hz; 1000 Hz; and 2000 Hz. An analysis of the relative energy levels in the four frequency bands can be performed to determine whether the fluid movement is single-phase or dual-phase flow and to determine the location of the flow source with respect to the individual well components.

Single-phase flow (either all liquid or all gas) is characterized by higher frequency sound. Thus, single-phase flow can be recognized by the close spacing of the 200, 600, and 1000 Hz curves, and the separation of the 2000 Hz curve on the noise log. At a single-phase flow noise peak, the four curves may nearly converge (Figure 26A).

Dual-phase flow (a combination of liquid and gas) is characterized by lower frequency sound. Thus, dual-phase flow is indicated by the separation of the 200 Hz curve from the others (Figure 26B) (Pennebaker and Woody, 1977). The degree of separation of the 200 Hz curve from the other three curves will vary depending upon the low-frequency noise associated with the two-phase flow (Robinson, 1976a).

At a noise peak, the frequency distribution of the noise will provide a clue to the pressure differential there. The greater the pressure differential, the higher the noise frequency will be and the less the separation will be between the four frequency curves. For example, at a noise peak where the pressure differential is so high that nearly all the noise is above 2000 Hz, the four frequency curves on the noise log will converge to almost the same value (NL McCullough, no date).

It is possible to detect flow behind the casing by an examination of the 2000 Hz curve, because as differential pressure in constrictions in channel behind the casing increases, the 2000 Hz

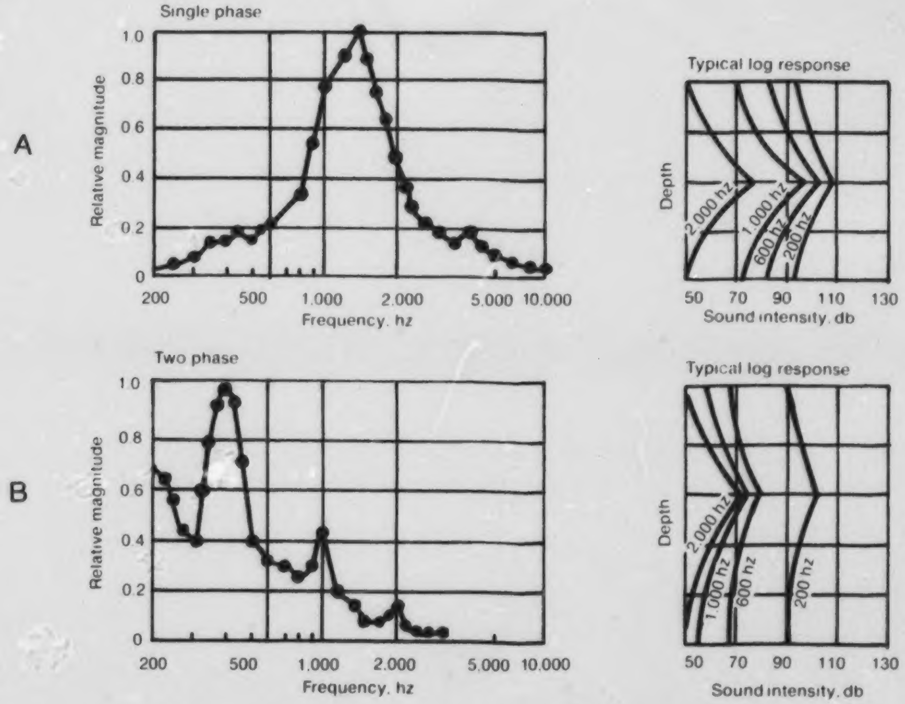


Figure 26. Distinctive noise log frequency distributions (Pennebaker and Woody, 1977).

noise level increases. Any significant deviation of the 1000 Hz curve from the background levels reveals a problem with a leak in the casing (Robinson, 1976a).

It is possible to estimate the rate and volume of flow from the amplitude of each of the individual frequency curves. A more accurate determination of rate and volume of flow can be made with the use of an empirical formula. The reader is referred to McKinley et al. (1973) and Britt (1976) for methods to accurately determine leak rates and volume of flow.

Several factors associated with the actual well completion and subsequent production or injection operations will influence interpretation and should be known to the operator at the time the survey is conducted. The construction details of the well generally do not affect either the operation of the sonde or the interpretation of the noise log. However, the transmission of sound energy through the well and the wellbore is to some degree affected by the various well components, including the cement, the casing, the annulus fluid and the tubing. For example, when the logging sonde is run in a tubing string, the amplitude or strength of the noise signal generated by a leak in the casing or by fluid movement behind the casing is somewhat subdued because of the "buffering" effect of the fluid in the casing-tubing annulus. Alternately, if there is a leak into the string containing the sonde, a different problem results. McKinley et al. (1973) have compiled a set of factors for various well completion types by which recorded noise levels may be multiplied to compensate for differences in well construction (Table 11).

Because the noise signal recorded on the log is interpreted relative to background noise levels, compensating for differences in well construction is generally not a problem to a skilled log analyst. Problems in the interpretation of the noise log may arise because of the scales used for depth and amplitude. If these scales are not properly selected, subtle changes in noise may go unrecognized. Pennebaker and Woody (1977) suggest that it may be very difficult to make an accurate diagnosis of downhole problems from a log displayed on a 5 inch = 100 foot scale.

COST

The cost of conducting a noise logging survey is dependant upon the many general pricing variables outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Table 12.

TABLE 11. WELL GEOMETRY FACTORS TO COMPENSATE FOR RECORDED NOISE LEVELS (McKINLEY ET AL., 1973)

Type of Well	Fluid Content	Factor
Tubingless Completion	Liquid in String	1.0
Tubingless Completion	Gas in String	1-2
Tubing String in Casing	Liquid in Tubing Liquid in Annulus	2
Tubing String in Casing	Gas in Tubing Liquid in Annulus or Vice Versa	2-4
Tubing String in Casing	Gas in Tubing and Annulus	5-10
Leak into Same String as Detector	Liquid in String	0.06
Leak into Same String as Detector	Gas in String	0.20

TABLE 12. TYPICAL DEPTH AND LOGGING CHARGES FOR NOISE LOGGING

Depth Charge	Low	High
per foot	$0.26	$0.29
minimum	$540.00	$700.00

Logging Charge	Low	High
per foot	$0.26	$0.29
minimum	$520.00	$580.00

Refer to Table 7 for a list of companies surveyed which perform this service.

ADVANTAGES AND DISADVANTAGES

The noise survey offers several advantages over other methods of determining mechanical integrity of injection wells. The primary advantage is that it can be utilized to detect both leaks in the casing and channeling in the cement sheath behind the casing. In addition, through the unique interpretation methods used with this survey, it is possible to distinguish whether an anomaly detected by the survey is caused by single-phase or dual-phase flow. Also, under some conditions, it is possible to estimate both the rate and volume of flow from a source that is detected by the noise logging sonde. The sonde itself offers an advantage in that it can not only be used in casing, but it is small enough to be used in tubing as small as 1 1/2 inches inside diameter.

Several disadvantages of the noise survey are apparent. The main drawback of the noise logging technique is the logging speed which can be achieved if noise sources are detected. Because the operation of the tool demands that the survey be conducted on a station-by-station basis, pinpointing noise sources can be a very time-consuming task. Also, while interpretation appears to be very straightforward, it is easy to misinterpret the data obtained with a noise survey, particularly if the interpreter is not experienced. Other logs (i.e. a temperature log) may have to be run in conjunction with the noise survey to more narrowly define any anomalies recognized by the noise logging sonde. In addition, as Arnold and Paap (1979) point out, since the noise amplitude generated by turbulence from high-energy expansion of fluids is a direct function of energy dissipated in the expansion process, the noise logging technique may not be useful in detecting water channeling when pressure differentials are too small to generate detectable noise amplitudes.

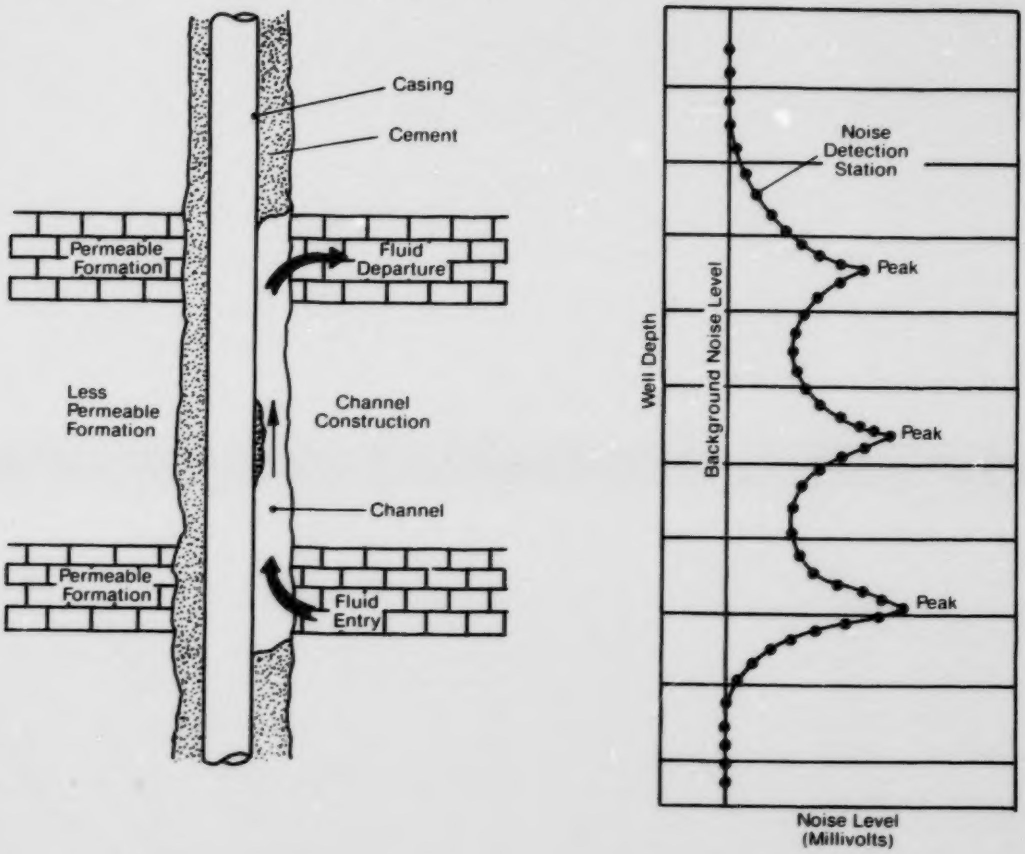
EXAMPLES

Figure 27 illustrates a typical noise log of a well in which fluid movement in a channel behind the casing is detected. As the figure shows, fluid enters the channel at a point opposite a permeable formation, moves upward, and exits the channel at another permeable formation. This example illustrates several important facts. First, noise levels are greater than the background level over the entire length of the channeled section where fluid is moving. Second, the top and bottom peaks indicate the points of fluid entry and exit. However, the direction of fluid movement must be inferred without additional information. Third, the middle noise peak on the log, the result of a constriction in the channel in the cement, appears the same as the other noise peaks. This could lead to a different interpretation of the log. These problems could be solved if additional information about the noise source was available.

The noise log has been used in combination with other logs to enhance the utility of each log. For example, when used with a temperature log, a noise log may have greater meaning with regard to determination of the type of anomaly in the well causing the disturbance. Both temperature and sound profiles reinforce one another and enhance interpretation.

Pennebaker and Woody (1977) have described a technique using condensed and expanded depth scale presentations of both sound and temperature data which has proved helpful in diagnosing well problems, particularly those producing subtle changes in sound and temperature. The system developed to implement this technique is depicted in Figure 28. As an example of how this system can be used, if flow is detected behind the casing with the noise log, the temperature log may indicate the direction in which fluid is moving through channels in the cement sheath. By comparison, where each log is run independently in a well, interpretation of both of the logs is more difficult and may well show very different situations downhole.

Another example, this of a producing well with channels or communication behind cemented casing, is offered by Robinson (1976b). Figure 29 shows two log sections from a two zone, two tubing string completion in Louisiana. Tests indicated that both zones produced 2800 mcf of gas, 42 barrels of oil and 1000 barrels of water per day. The water seemed to be extraneous to both zones and began nearly simultaneously. One conclusion was that communication existed between the two zones. BHP tests were inconclusive. A tubing leak and communication behind casing was suspected, but not proven. A spinner flowmeter survey was ruled out because of the possible behind- pipe communication. The decision was made to run a noise log to determine behind-pipe communication, tubing or casing leaks and a possible packer leak. The logging tool was in the long string for the three runs shown in Figure 29A and 29B.



Physical Condition of Well

Noise Log Display

Figure 27. Typical noise log display.

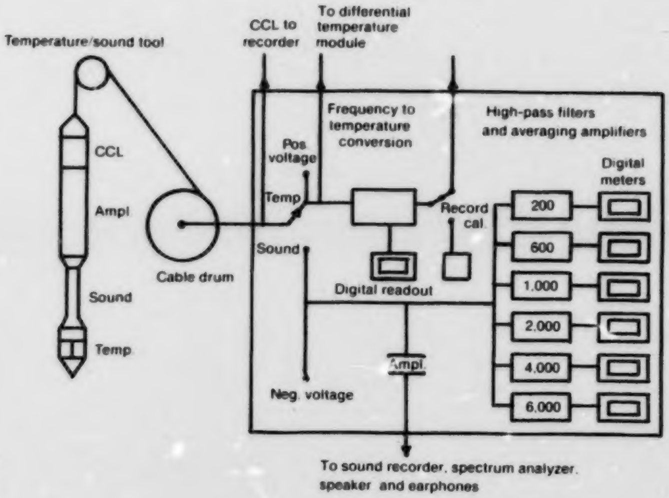
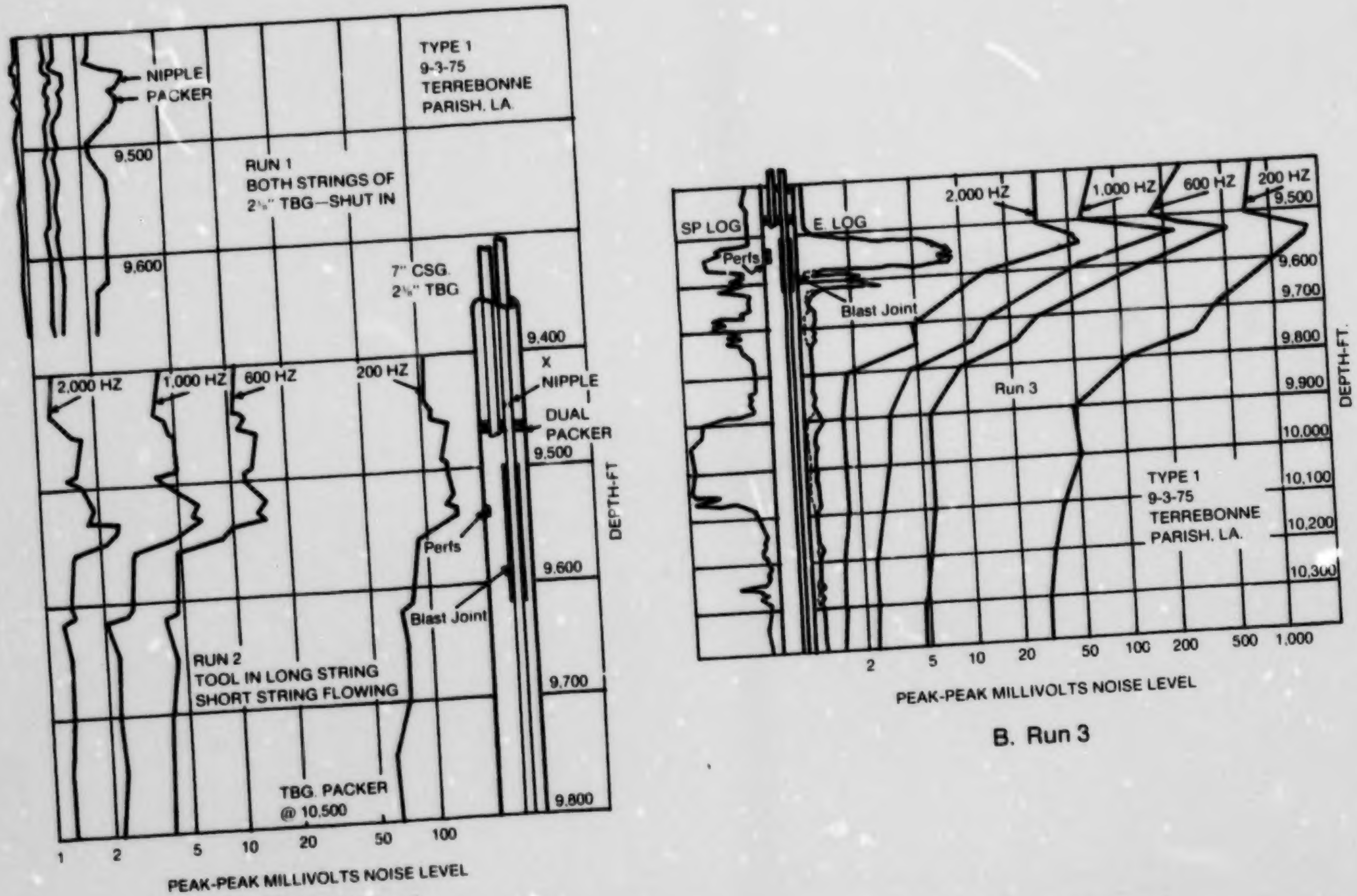

Temperature/sound tool
CCL to recorder
To differential temperature module
CCL
Ampl
Sound
Temp
Cable drum
Frequency to temperature conversion
High-pass filters and averaging amplifiers
Pos voltage
Temp
Sound
Record cal.
Digital meters
200
600
1,000
2,000
4,000
6,000
Digital readout
Ampl.
Neg. voltage
To sound recorder, spectrum analyzer, speaker and earphones

Figure 28. Combination noise/temperature survey system (Pennebaker and Woody, 1977).



A. Run 1 and Run 2

B. Run 3

Figure 29. Noise log sections from a 2-zone, 2 tubing string completion (Robinson, 1976b).

Both strings were shut in to log Run 1. This run did not show any flow of significance; however, it does furnish a base or reference log. Run 2 is a log over the same interval as Run 1 with the long string shut in and the short string producing water, oil and 1500 mcf of gas per day. Comparing Run 2 with Run 1, the increased separation between the four curves, especially the 200 HZ, indicates two phase flow through the entire interval. The peaks on all four curves opposite the perforations are an indication the zone is producing. The shift of all four curves at 9616' indicate there is two-phase flow inside the 7" casing past the foot of the long-string blast joint. This shift is due to a difference in the cross section area caused by the 3" O.D. blast joint compared to the 2 3/8" O.D. tubing. There weren't any indications of a hole through this interval and the conclusion was that the packer was probably leaking.

Figure 29B is Run 3 from the same well as Figure 29A. The short string was shut in and the log was run in the long string while it was producing. There are at least two indications of problems on the log:

1) the relative amplitude of the peaks opposite the perforations which are supposed to produce into the short string and

2) a significant shift on all four curves beginning at 9750'.

The high noise level at the perforations for the short string indicate a hole in the blast joint. All four curves shifting at 9750' indicates behind casing flow or a hole in the casing or tubing. The SP and E log indicate a water sand at that depth and, regardless of whether the problem is, a hole or behind pipe flow, the water source is at 9750'.

To review the interpretation, there was a hole in the long string blast joint, behind pipe communication from 9750' to the short string perforations and a probable packer leak at 10,500'.

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SECTION 10

PIPE ANALYSIS SURVEY

SYNOPSIS

The Pipe Analysis Survey (PAS), which was developed to detect downhole corrosion damage, is also able to provide information on other types of casing damage. Through interpretations of the log produced by the PAS tool, the following conditions may be evaluated (Bradshaw, 1976):

- the approximate range of nominal casing body wall penetration;
- whether the damage is on the inside casing wall (internal) or the outside casing wall (external); and
- whether the casing damage is isolated or circumferential.

The PAS functions as a "microscopic" casing inspector. It is primarily used to detect the presence of small casing defects, such as corrosion pitting. Tests indicate that casing anomalies as small as 1/8" in diameter for inner wall defects and 3/8" in diameter for outer wall defects with as little as 20% nominal body wall penetration can be detected and recorded with the PAS (Smolen, 1976). Although small defects are easily observable on the PAS log, large-scale conditions, such as casing splits, are often impossible to discern. The PAS tool can inspect casing from 4 1/2" to 9 5/8" diameter. Because the tool is centralized in the casing and has multiple and independent measuring devices, the PAS inspection covers the full circumference of the casing. The PAS is capable of inspecting only the inner string of multiple casing strings.

The PAS tool detects casing defects such as holes, gouges or cracks, by measuring fluctuations in an induced magnetic field with coils mounted in small pads. The PAS is able to discriminate between defects on the inside and outside of the casing wall by means of a high-frequency eddy current test, which detects flaws on only the inner surface, and a magnetic flux leakage test, which inspects the full casing thickness. An evaluation of the various nondestructive mechanical integrity testing techniques indicates that a combination of high-frequency eddy current and magnetic flux leakage tests provides an optimum approach for in-place inspection of well casings to detect small, isolated defects or corroded areas and to determine whether they are located on the internal or external casing wall.

PRINCIPLES

Magnetic flux leakage testing relies on the detection of perturbations in an induced magnetic field caused by defects in the casing of a well. Implementation of this technique requires a source of magnetic flux and sets of pick-up coils that ride the inner surface of the casing on an array of pads. If DC current is sent through a coil of wire (the electromagnet within the PAS tool), a magnetic field is generated along the axis of the coil (Figure 30). The magnitude of the magnetic field is primarily determined by the product of the current through the coil in amperes and the number of turns in the coil.

A magnetic field consists of an infinite number of lines of force called magnetic lines of flux. These have two basic properties which the PAS system uses:

- the magnetic lines of flux travel through casing more readily than through air or fluids; and
- one line of magnetic flux cannot cross another line of magnetic flux.

Energy, in the form of magnetic flux, is introduced into the pipe wall. The pipe itself acts as a conducting medium and conveys the magnetic lines of force. If the casing body wall is consistent, and no anomalies are present, the lines of magnetic flux are uninterrupted. Any anomaly in the casing will cause a leakage of flux from the casing wall; the lines of flux alter their path and create a "fringing" or bridging pattern over and around the anomaly since, at the defect, there is less iron in the pipe to conduct the magnetic flux (Figure 31). The amount of fringing or bridging is directly proportional to the geometry and the percentage of penetration of the anomaly.

The fringing flux, which extends into the hole, is detected by pick-up coils or transducers, mounted on the PAS tool, which provide a full 360° coverage of the circumference of the casing. As these sensors pass through an area of flux leakage, an electrical signal is produced. The magnitude of this signal is determined by the pick-up coil size, the rate at which the coil passes through the area of leakage, and the amount of leakage through which the coil passes. Because the size of the pick-up coils is constant and the rate at which the coils pass through an area of leakage (logging speed) is relatively constant, the magnitude of the voltage generated in the transducer is proportional to the percentage penetration of the anomaly relative to the nominal casing body wall.

The magnetic flux path, which is distorted in the vicinity of a defect, has a small component normal to the casing wall both above and below the defect. As the flux leakage coils pass over the defect as

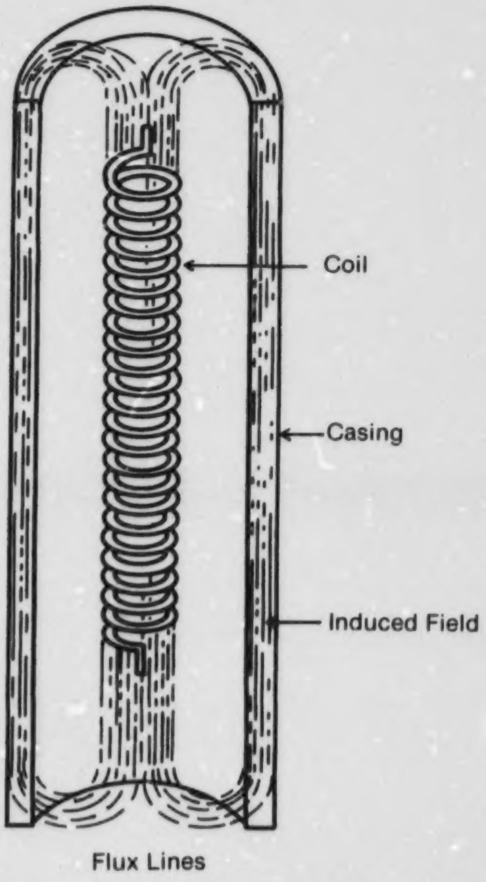
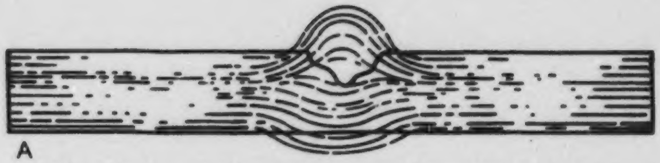
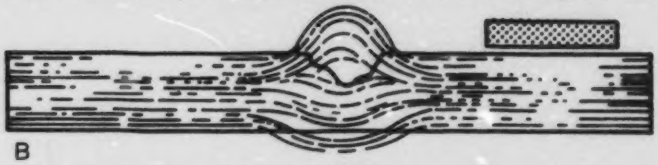


Figure 30. Diagram of magnetic field being induced into the casing body wall (Bradshaw, 1976).



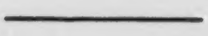
A

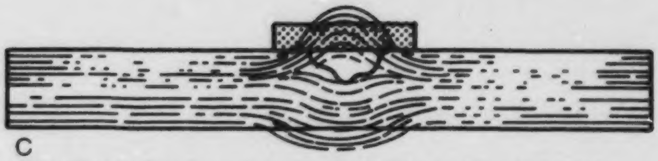
A Visualization of Magnetic Lines of Flux Flowing Around a Pit in Casing Inner Wall



B

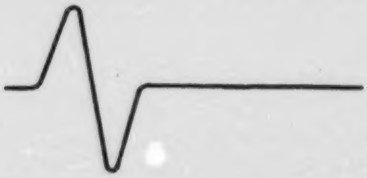
The Signal Produced as a Pad Approaches the Pit

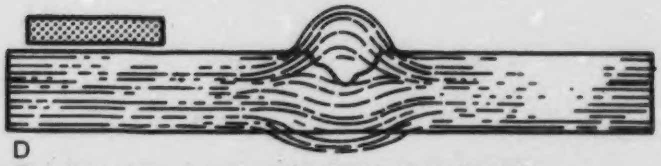




C

The Signal Produced as the Pad Passes Over the Pit





D

The Signal Produced as the Pad Leaves the Pit

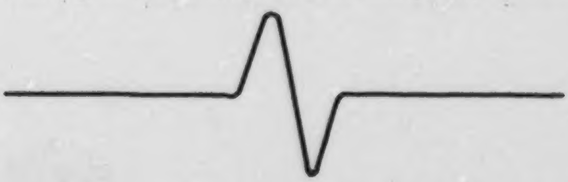


Figure 31. Diagram of the response of the pipe analysis log to a casing defect (After Bradshaw, 1976).

shown in Figure 32, this component grows from zero to a maximum and then back to zero, thereby inducing a current in each of the flux leakage coils. Since the coils are at different points in the field, the current induced in each is different. The differences in the induced currents in the upper and lower flux leakage coils is a measure of the rate of change of the flux vector into the well bore and hence of the magnitude of the defect.

The amount of flux leakage detected by a transducer is related to the location of the anomaly with respect to the transducer. Relative to the instrument, this means that an internal anomaly will generate a signal of greater magnitude than an external anomaly of the same penetration.

The overall system for defining internal and external defects uses a technique known as eddy current sensing. By varying the amplitude and polarity of current flowing through a coil, a corresponding variance in the amplitude and polarity of the magnetic field produced by the coil will occur. If an electrical conductor is placed in this varying magnetic field, small varying currents known as eddy currents will be set up in the electrical conductor due to the relative movement of the magnetic field with respect to the electrical conductor.

As Figure 33 illustrates, a high-frequency current in the eddy current coil generates a magnetic field, B_C, which induces a circulating current; i_i, in the casing. This induced current generates a countervailing field B_i in the casing wall. The resulting field intensity is detected by the flux leakage coils and separated from the flux leakage signal by a frequency filter. Flaws in the casing surface impede the formation of circulating currents and hence have a substantial effect on the distribution of the induced field, B_i. Changes in the difference in the induced currents in the sensing coils, i_1-i_2, are a measure of surface quality. The effect of good and bad casing on this test is shown in Figure 33.

The amplitude of current passing through the eddy current coil is affected by the distance of the coil from the conductor, the electrical conductivity of the conductor, the permeability of the conductor, the magnetic reluctance of the metal, the current frequency, and the amount of conductor present. A change in any of these factors will produce a corresponding change in coil current amplitude. For the eddy current test, a transmitter coil is mounted above the pick-up coils in each pad on the instrument. Frequency for the eddy current test is chosen so that the depth of investigation is only about 1 mm into the inner casing wall; as a result, this test is insensitive to outer surface casing defects. Thus, simultaneous defect signals from both the eddy current and the magnetic flux leakage tests indicate that the defect is on the inner surface of the casing. On the other hand, an indication from the magnetic flux test with no indication from the eddy current test indicates the defect to be on the outer surface of the casing (see Figure 38).

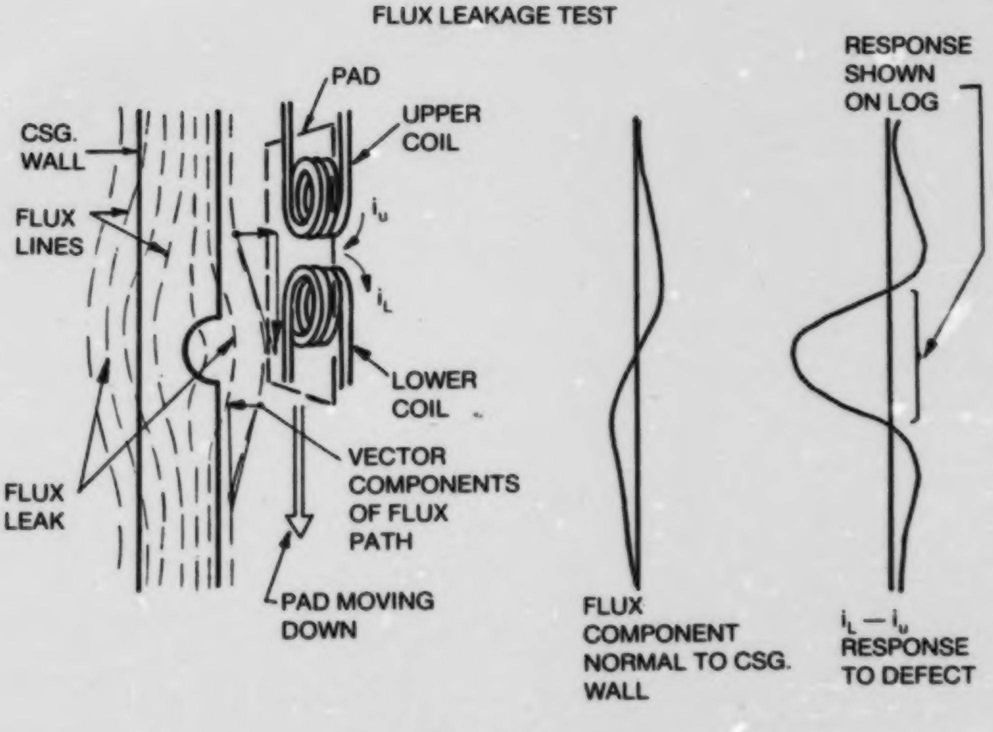


Figure 32. Principle of operation of magnetic flux leakage test (Smolen, 1976).

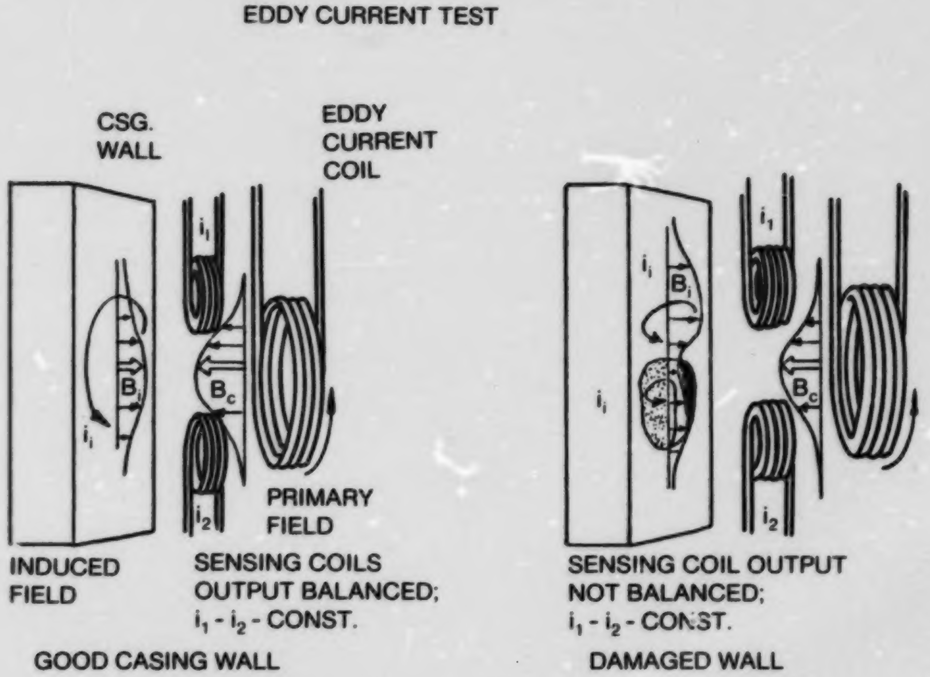


Figure 33. Principle of operation of eddy current test (Smolen, 1976).

EQUIPMENT

The basic downhole PAS tool consists of a sonde, an upper and lower cartridge (each an electronics package) and two centralizers (Figure 34). The sonde is comprised of an electromagnet and two arrays of pads consisting of six pads each. The electromagnet within the sonde is a coil of wire wound on a core passing through the center of the sonde. Regulated DC current is sent to this coil from the surface instrumentation via a wireline. The magnitude of the magnetic field generated by the coil is made great enough to saturate the body wall of the casing with lines of magnetic flux. Magnetic pole pieces are mounted above and below the pad arrays. The pole pieces are changed for various sizes of casing to be inspected so that there is approximately a 1/4" gap between the pole piece and the casing.

The sensing width of each pad is two inches. The pads are arranged as shown in Figure 35 in upper and lower arrays of six pads each to assure total casing coverage (Smolen, 1976). In most casing sizes, there is a degree of double coverage due to overlapping of the pad paths. Hence, some portion of the casing may be examined by a pad in each of the upper and lower arrays while other portions of the casing may be only examined once. The pads are spring loaded and adjust for casing sizes from 4 1/2" to 9 5/8" outside diameter.

The pads each contain a pair of coils on their inner surface to detect flux leakage. These are referred to as the upper and lower flux leakage coils and are situated within the pad as shown in Figure 36. Centrally located on the inside of the pad is a third coil used for the eddy current test. The pad is oriented in the well bore with the flux leakage coils one above the other. These transducers are located in such a manner that the area of casing affecting the eddy current transducer is also the area containing a potential anomaly which would affect the flux leakage transducer. Each transducer is connected to one of the cartridges on the tool.

The two cartridges relate directly to the two principles used by the system -- one supports the magnetic flux leakage test and one supports eddy current testing. One of the cartridges thus processes the signal received from the flux leakage transducer, relating to the severity of casing damage, and the other cartridge is dedicated to discriminating between internal and external anomalies. The cartridge supporting the flux leakage test is divided into two sections corresponding to the two arrays of pads on the instrument. Each array of pads has a readout channel at the surface for flux leakage detection. The top ring of pads produces one channel and the bottom ring of pads the second channel.

An uphole signal processing panel is connected to the downhole tool via a conducting wireline. The uphole panel provides power for the downhole cartridges, DC power for the electromagnet, and uphole signal processing circuitry.

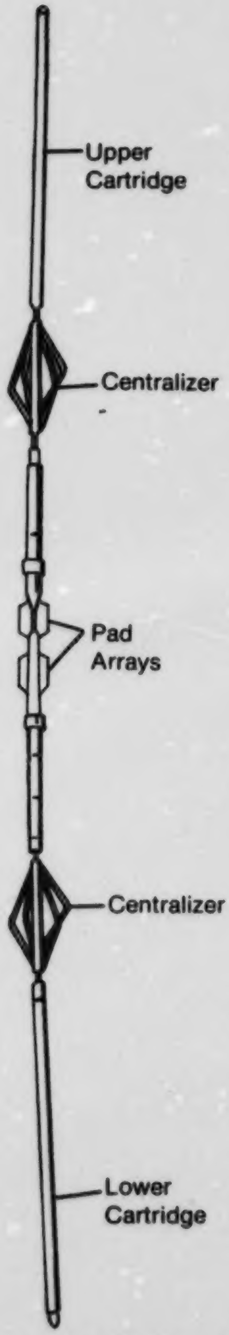


Figure 34. The pipe analysis survey tool (Cuthbert and Johnson, 1974).

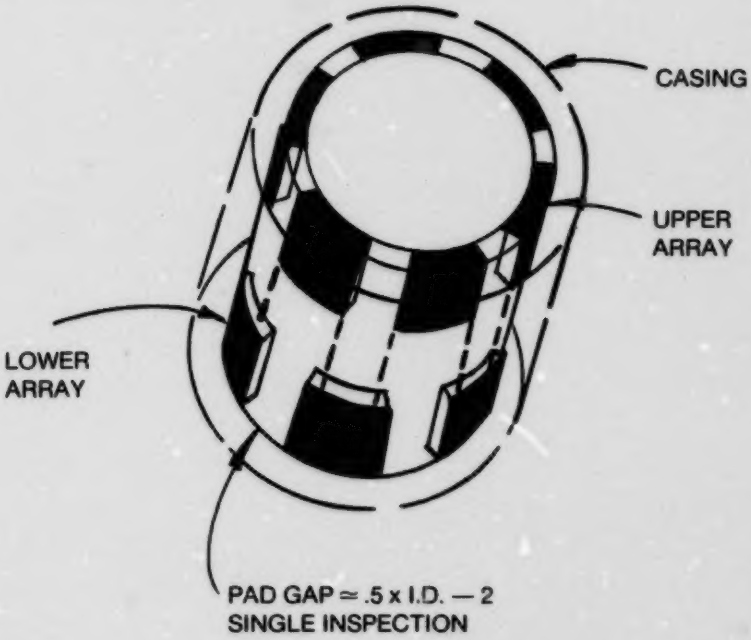


Figure 35. Diagram of pad overlap (Smolen, 1976).

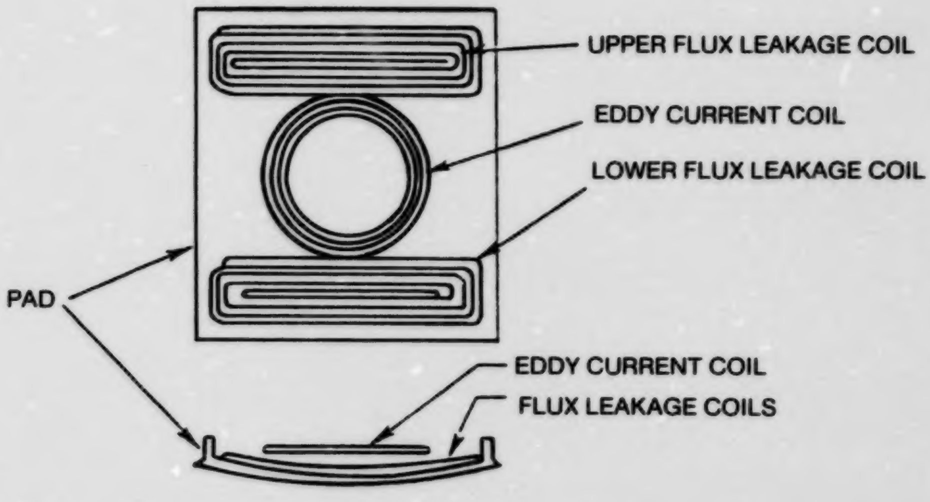


Figure 36. Diagram of pad configuration (Smolen, 1976).

The downhole tool will operate in temperatures and pressures up to 250°F and 10,000 psi respectively.

PROCEDURES

Prior to logging each well, the system is calibrated by inducing a magnetic signal of a known level into each transducer. Each transducer is connected to its own amplifier located in the instrument. With the instrument connected to the wireline, each amplifier is adjusted so that the magnetic signal induced in its respective transducer produces the same number of chart divisions on the readout system. This calibration procedure is necessary to ensure that each of the transducers will react as identically as possible to the same anomaly.

The PAS downhole tool is lowered down the well on a wireline to the desired depth of investigation. The pads are then extended via a spring-loaded mechanism until they contact the well casing. DC current is supplied to the electromagnet contained within the sonde. The tool is then pulled up the well on the wireline, centered in the well with centralizing devices on either end of the tool.

The magnetic field generated by the electromagnet causes magnetic flux lines to permeate the casing in a direction parallel to the well bore. Anomalies in the casing distort the flux path, causing some flux lines to bridge around the defect. Defects are detected by sensors located in each of twelve pads in two pad arrays. Electrical signals generated by casing defects are then amplified and sent uphole to receiving equipment at the surface, where the data generated by the downhole tool is recorded and later interpreted.

Any scale buildup on the inside of the casing may be a potential problem to the operation of the PAS tool in the well. While this does not directly affect the measurements made by the tool, scale deposits may adversely affect the ability of the tool to be pulled back uphole, since pads which contact the inside of the casing are used in making measurements.

INTERPRETATION

PAS data consist of four channels of information on one type of log, and two channels of information on another type of log. Interpretation of the PAS log, then, consists of reading and deciphering either the four channels of information on the one type of log or the two channels contained on the other type of log.

The first two channels of the first type of PAS log (Figure 37) are called flux leakage channels -- they correspond to the two rings of pads on the downhole tool. These two channels relate to the overall condition of the casing with respect to pitting. Since the flux leakage test is sensitive to the gradient of the component of magnetic flux lines normal to and into the well bore, it is in reality

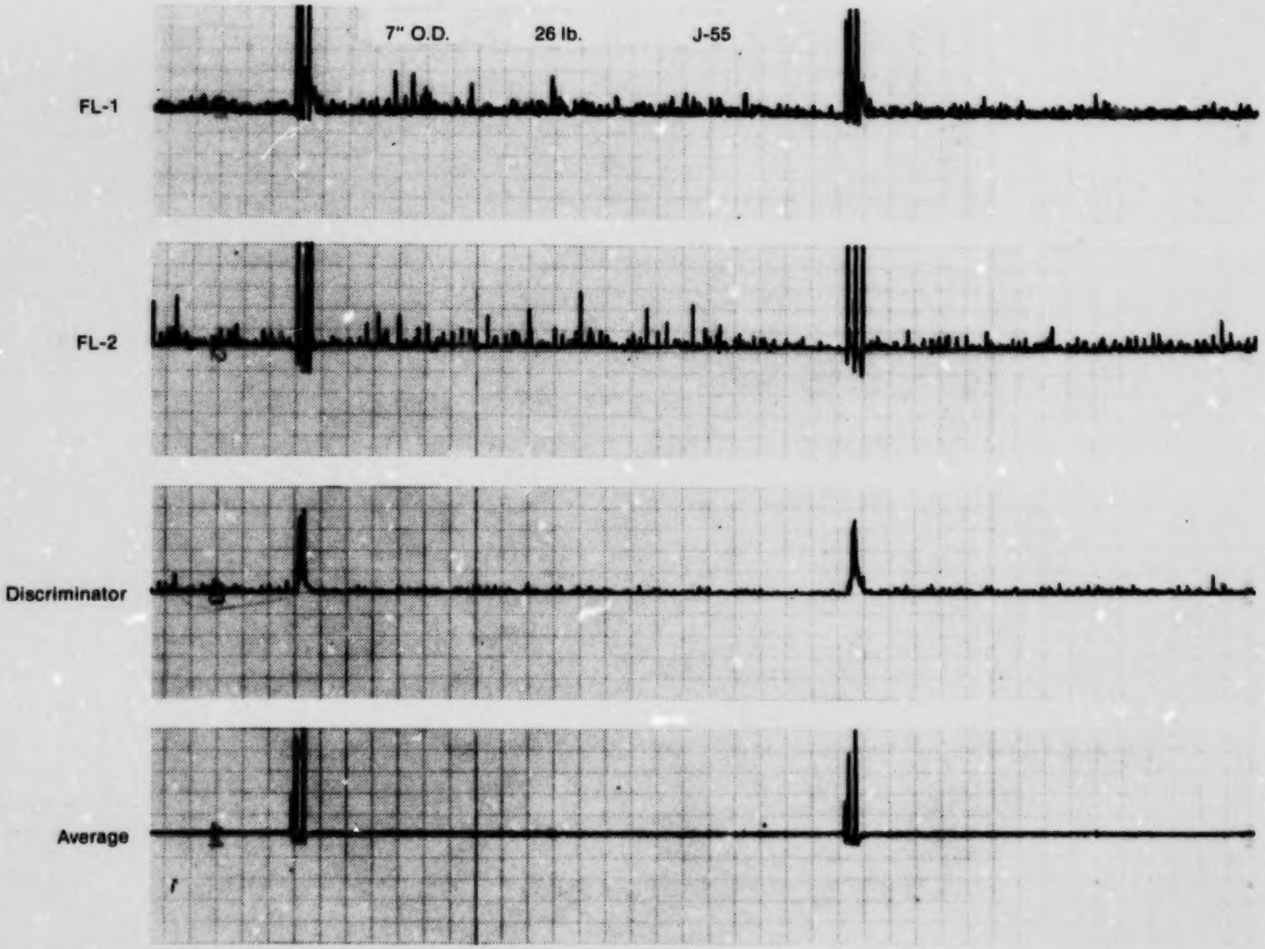


Figure 37. Example of four-channel output from one type of PAS log (Bradshaw, 1976).

sensitive to the abruptness of the defect's occurrence, as seen when the tool moves uphole. A gradually occurring defect will not be detected unless some surface roughness or pitting is present. The signal which appears on each of the first two channels is the maximum of the signals generated by each of the six pads in an array.

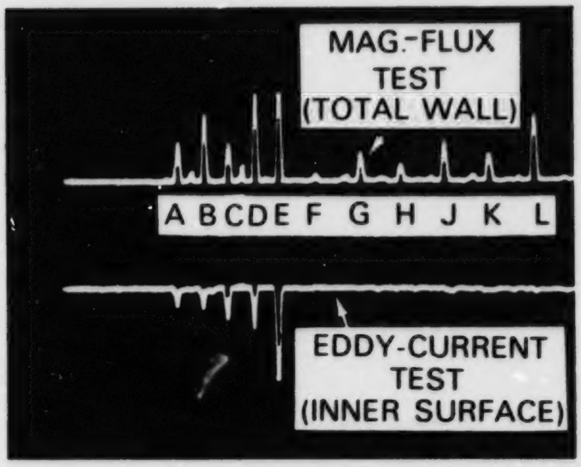
The third channel is referred to as the "discriminator" channel. Any change in current amplitude is sensed by the eddy current coils which in turn send a signal to the discriminator channel. If the signal on the discriminator channel has a corresponding signal on the first or second channel, that signal is interpreted as an internal anomaly. If there is no corresponding signal on the first or second channel, the signal on the discriminator channel is ignored.

The fourth recording on the PAS log, the "average" channel, relates the effect of the cross-sectional area of the casing, thus allowing for interpretation of the results from the first two channels. It has been found from field tests that a circumferential anomaly will produce a higher indication than an isolated anomaly of the same body wall penetration. To help differentiate anomalies, all transducers in the top ring of shoes are connected to a circuit which produces the average channel readout. The averaging circuit takes a portion of the signal produced by each transducer in the top ring of shoes and adds all of the portions together. The output of the averaging circuit is proportional to the number of top ring transducers that produced a signal at the same time. A casing collar, for example, produces an equal signal on all transducers, and thus appears as a 360° anomaly.

If the intensity of the indication produced by the average channel is divided by the number of transducers located in the top ring of shoes, the contribution of each transducer to the total intensity of the indication can be determined. Experimentation has shown that an anomaly which produces a signal on the average channel equal to the contribution of 2 1/2 transducers should be interpreted as circumferential in nature (Bradshaw, 1976).

The average channel also serves as a guide to help evaluate the proper operation of the instrument. Any signal which is recorded on the first channel must have a corresponding signal on the average channel. Because of the difference in the method of signal processing, a signal recorded on the average channel does not imply that the signal should have been recorded on the first channel.

The oscilloscope traces on Figure 38 illustrate the information contained on the second type of PAS log. The signals shown are from a sonde as it was pulled through a pipe with various known defects in the laboratory (Cuthbert and Johnson, 1974). The upper trace is the flux leakage test signal and the lower trace is the eddy current test signal. The first five defects, A through E, are on the internal wall; they are drilled holes ranging from 3/8 in. diameter with 25



DEFECT	LOCATION	DIAM. (in.)	PERCENT WALL PENETRATION
A	INTERNAL	3/8	25
B	INTERNAL	3/8	50
C	INTERNAL	1/2	25
D	INTERNAL	1/2	50
E	INTERNAL	3/4	25
F	EXTERNAL	3/8	25
G	EXTERNAL	3/8	50
H	EXTERNAL	1/2	25
J	EXTERNAL	1/2	50
K	EXTERNAL	3/4	25
L	EXTERNAL	3/4	50

Figure 38. Oscilloscope traces of a laboratory PAS log (Cuthbert and Johnson, 1974).

percent wall penetration to 3/4 in. diameter with 25 percent wall penetration. Since both the magnetic flux leakage test and the eddy current test show anomalies, the defects are indicated to be on the internal wall surface. The next six defects, F through L, are on the outside wall and range from a 3/8 in. diameter pit with 25 percent wall penetration to a 3/4 in. diameter pit with 50 percent wall penetration. In this instance, anomalies are indicated by the magnetic flux leakage test, but not by the eddy current test, indicating that the defects are confined to the outer surface.

On a variety of the second type of PAS log, which consists of two channels of information plus a composite curve, the first two channels correspond to the two arrays of pads on the tool (Figure 39). One channel corresponds to the signal produced by the lower array of pads, and one corresponds to the upper array of pads. On this log, each array produces two curves, one which relates to the condition of the inner surface of the casing and to the eddy current test, and one which relates to total wall thickness and thus to the flux leakage test. The traces in the left-hand track are referred to as "enhanced curves." Each of the two enhanced traces is derived from the corresponding maximum signal from any of the twelve pads in the upper and lower arrays. There is a provision to make large deflections more visible on the enhanced curves by holding the recording device at the maximum deflection for a short period of time after the maximum is reached. If a second defect were to occur during the hold period, it will not appear on the enhanced curves. Thus, vertical resolution is lost on the enhanced curves, but major defects can be made more apparent.

External metallic hardware which is in contact with the casing (i.e. scratchers or casing centralizers) will also produce a change in magnetic flux in the hole, which will be detected by the PAS tool. Thus, information concerning the placement of exterior hardware is essential for correct log interpretation.

COST

The cost of conducting a pipe analysis survey is dependant upon the many general pricing variables as outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Table 13. Refer to Table 7 for a listing of companies surveyed which perform this service.

ADVANTAGES AND DISADVANTAGES

The PAS offers several advantages in mechanical integrity testing in that it was developed specifically to evaluate downhole casing damage. It is able to distinguish between internal and external casing damage and can determine whether the casing damage is isolated or circumferential. Even relatively small defects in casing (1/8" diameter for inner wall defects; 3/8" diameter for outer wall defects)

TABLE 13. TYPICAL DEPTH AND LOGGING CHARGES FOR PIPE ANALYSIS SURVEYS

Depth Charge	Low	High
per foot	$0.29	$0.30
minimum	$580.00	$600.00
Logging Charge	**Low**	**High**
per foot	$0.28	$0.29
minimum	$560.00	$580.00

can be detected by PAS. The combination of high-frequency eddy current and magnetic flux leakage tests in one tool appears to offer the best available approach for detecting casing defects.

Several disadvantages in the use of the PAS for mechanical integrity testing are also apparent. The primary disadvantage is that the PAS is offered by only a few well servicing contractors. Additionally, interpretation of the log produced by the PAS must be done by a highly skilled log analyst.

Because of the size of the tool used, the PAS can only be utilized inside casing, and thus cannot be used to inspect tubing. The tubing must be removed from the well before the PAS can be run, necessitating a lengthy shut-down time for the well and possibly replacement of the packer. In addition, while the PAS can detect external casing defects, it cannot provide information on fluid migration in the cement sheath behind the casing.

EXAMPLES

Figure 39 is an example of a PAS log from a gas-storage well where the inner wall of the pipe is corroded. Interpretation of the data from the pipe analysis log indicates that the casing is free of defects below 70 ft. With the exception of one serious defect near 30 ft, the log indicates that the corrosion is light to moderate on the internal surface of the pipe. This string of pipe was subsequently pulled. Surface inspection confirmed that the casing below 70 ft is free of corrosion. Above 70 ft there is heavy scale build-up on the inner surface, with light to moderate pitting. The large indication on both the magnetic-flux-leakage and eddy-current tests is from a large pit, greater than 1-in diameter, with 20- to 30-percent wall penetration.

In another example from Cuthbert and Johnson (1974), Figure 40 shows the PAS tool response in 7-in casing in a laboratory test well with known defects. The bottom joint of casing from 20 ft down has

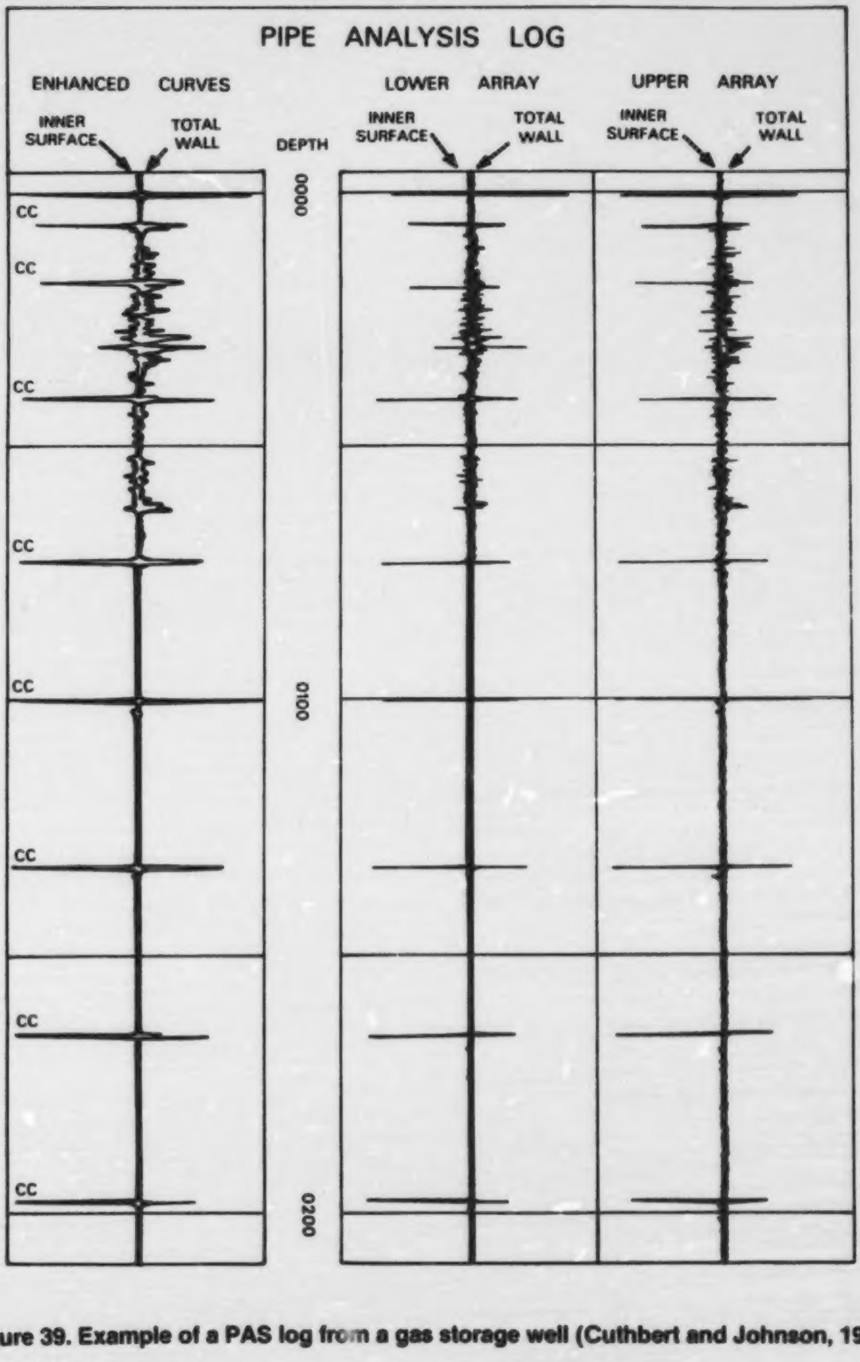


Figure 39. Example of a PAS log from a gas storage well (Cuthbert and Johnson, 1974).

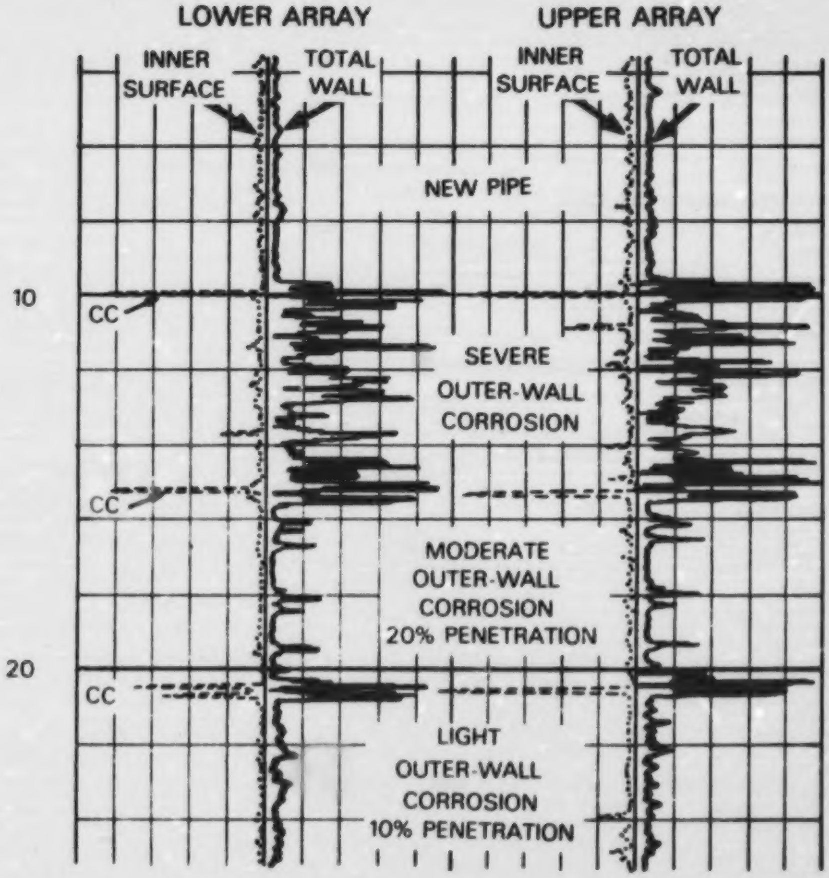


Figure 40. PAS tool response in a 7-inch test well with known defects (Cuthbert and Johnson, 1974).

light external corrosion--approximately 10-percent wall penetration. The joint from 15 ft to 20 ft has moderate external corrosion with approximately 20-percent wall penetration. The joint between 10 and 15 ft is corroded externally. The corrosion is so severe that there were several small holes, 1/4-in to 1/2-in in diameter, completely through the pipe. Except for the holes, which are detected by the eddy-current test, the inner surface is quite clean. The flux-leakage test, however, produces a dramatic log indicating the severity of the external corrosion.

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SECTION 11

ELECTROMAGNETIC THICKNESS SURVEY

SYNOPSIS

The Electromagnetic Thickness Survey (ETS) responds to general casing deterioration, including large-scale corrosion, casing splits and mechanical wear, by measuring the phase shift of a magnetic field induced by the tool. The ETS measures average casing thickness over a length of about two feet.

Stroud and Fuller (1961) list the applications of the ETS in production wells:

- to detect the progress of corrosion and determine the effectiveness of cathodic protection programs,

- to log casing where a re-drill is proposed to determine if the casing has adequate strength to support such an operation,

- to log casing to evaluate its salvage value, and

- to locate a leak and determine the general condition of adjacent casing to plan remedial action.

The log generated by the ETS tool is sensitive to variations in magnetic permeability and electrical conductivity of the casing. Because of this, it is most effectively used to monitor changes in casing condition over a period of time as an indicator of progressing casing damage. This requires a base log as a reference.

The ETS does have a somewhat limited resolution in that the smallest hole size it can detect is approximately one inch in diameter. It is used primarily to observe large-scale casing problems, such as splits or parting or large holes in the casing wall. It cannot discriminate between inner and outer wall defects.

The ETS tool utilizes the only measurement capable of detecting corrosion or other defects in the outer string of a double string of casing. It is capable of serving as an early warning device in double casing strings by indicating major alterations in the outer string.

PRINCIPLES

The ETS responds to the amount of metal surrounding the downhole tool by measuring the effect of eddy currents on a magnetic field. The downhole instrument used in the PAS consists of two radial coils--an exciter coil and a pick-up coil. An alternating current sent from the surface equipment to the exciter coil generates a magnetic field which sets up eddy currents in the casing wall. These eddy currents cause the magnetic field to be attenuated and shifted in phase, and the resulting magnetic field is detected by the pick-up coil. The phase of the signal induced in the pick-up coil lags the exciter coil current by an amount proportional to the average thickness of the casing (Figure 41). The signal detected by the pick-up coil is amplified and transmitted to the surface.

At the surface, in the uphole instrumentation, the signal from the downhole tool is separated from the exciter voltage and amplified. At this point, the signal is a true reproduction of the bottom hole signal from the pick-up coil. The phase of this signal is compared with the phase of the exciter voltage signal and the resulting phase shift is recorded.

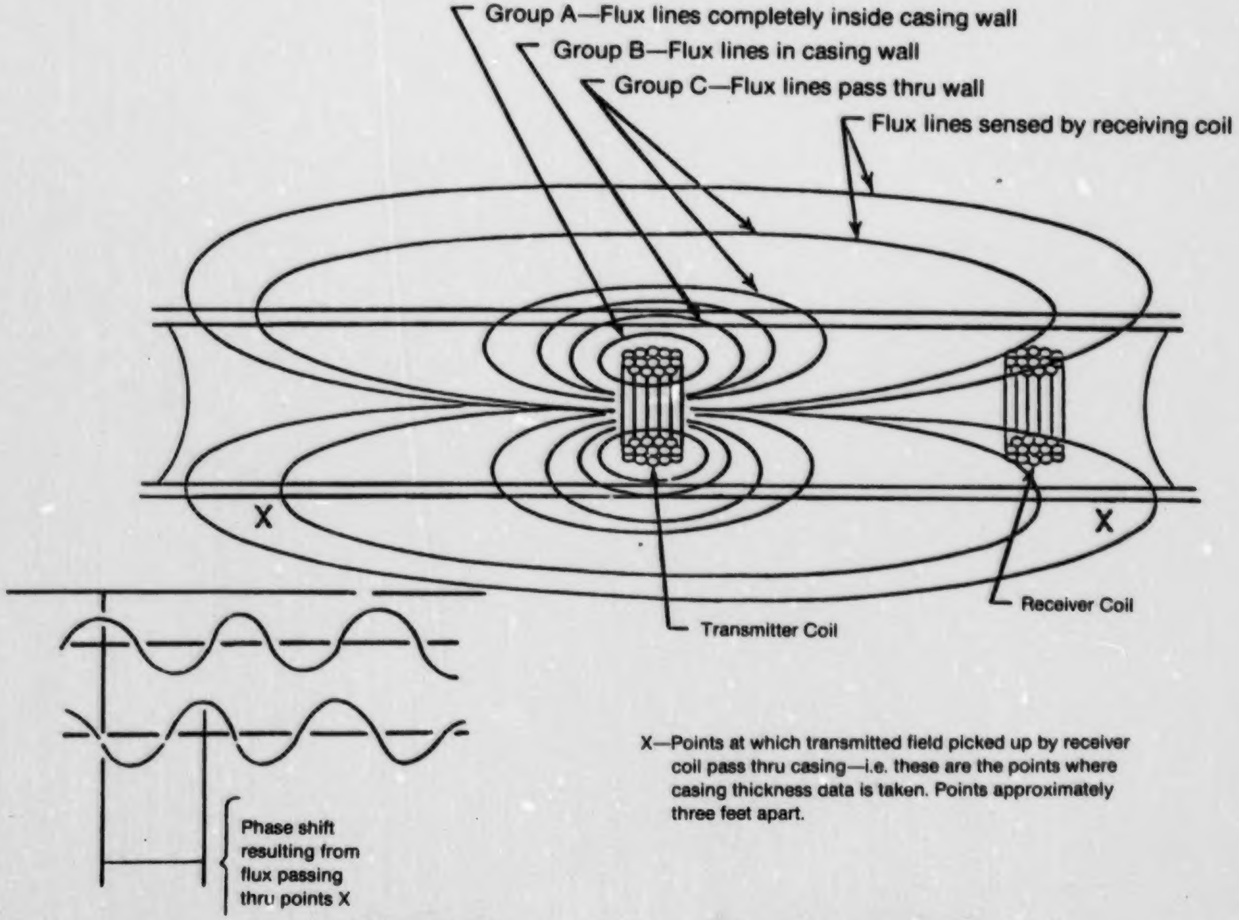
The theory of eddy currents indicates that phase shift is determined by four factors: casing wall thickness, frequency, magnetic permeability, and resistivity of the metal. The basic phase-shift equation:

$$\phi = 2\pi D \sqrt{\frac{F\mu}{\rho \times 10^3}}$$

where ϕ = phase shift (radians), D = casing thickness (meters), F = freauency (Hz), μ = magnetic permeability (Henrys/meter), and ρ = casing resistivity (ohms-meters); demonstrates that the phase shift is directly proportional to casing wall thickness.

The factors of magnetic permeability and metal resistivity vary considerably for casing from well to well and even from joint to joint within a well. Stresses placed upon casing installed in wells also seem to affect the magnetic permeability of the metal. This problem is minimized by running a base log early in the life of the well, for comparison with subsequent logs run in that well.

A modified ETS log was developed by one well servicing company to eliminate the dependence of the ETS on magnetic permeability and metal resistivity (Smith, 1980). The tool used in this survey measures magnetic permeability and computes true average wall thickness. It can, therefore, distinguish magnetic permeability variations from thickness variations. This is especially useful in older wells, where magnetic permeability can vary by as much as a factor of five (Smith, 1980).


Group A—Flux lines completely inside casing wall
Group B—Flux lines in casing wall
Group C—Flux lines pass thru wall
Flux lines sensed by receiving coil
X
X
Transmitter Coil
Receiver Coil
Phase shift resulting from flux passing thru points X

X—Points at which transmitted field picked up by receiver coil pass thru casing—i.e. these are the points where casing thickness data is taken. Points approximately three feet apart.

Figure 41. Diagram of principles of an ETS Survey (Smolen, 1976).

The modified ETS utilizes a multiple-frequency measurement scheme to determine average casing wall thickness, with six separate coils operated in pairs at three different frequencies (Figure 42).

A low-frequency magnetic flux induces eddy currents in the casing wall, much as the other surveys do. These currents cause a phase shift and amplitude attenuation in the flux flowing from the transmitter coil to the receiver coil. The resulting receiver coil voltage phase shift is a function of the casing thickness and magnetic permeability of the casing.

A mid-frequency measurement is used so that none of the transmitter-to-receiver flux penetrates through the casing wall. The receiver coil voltage at this frequency is dependent on the magnetic permeability and inside diameter of the casing.

A third, high-frequency measurement is made so that the transmitter-to-receiver flux penetrates only the inner skin of the casing wall. The high-frequency receiver voltage is thus a function of inside diameter only, allowing this measurement to serve as an electronic caliper.

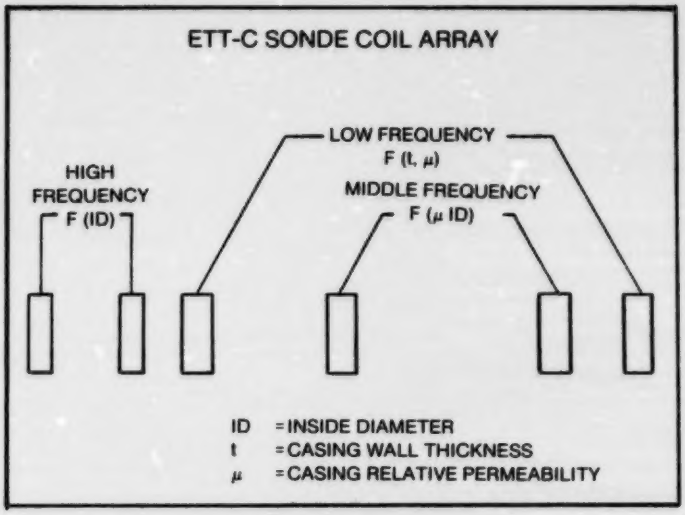
EQUIPMENT

The original ETS downhole tool, illustrated in Figure 43, consists of two radial coils -- an exciter coil and a pick-up coil. Centralizing springs are located at the top and bottom of the tool to minimize wear on the two coil housings. The tool is designed to withstand downhole temperatures and pressures of 350°F and 20,000 psi respectively. Tools are available for use in wells from 4 1/2 to 9 5/8 inches outside diameter.

In the surface instrumentation, the phase angle transmitted uphole via the wireline is measured by a solid-state phase detector. A linear output voltage, which is proportional to the phase angle, is produced to drive a strip-chart recorder.

The equipment utilized in the modified ETS differs in that the downhole tool consists of a sonde with six radial coils -- three transmitter-receiver pairs which utilize three separate frequencies -- an electronics cartridge to process the data and a telemetry cartridge to transmit the data uphole. The device is centered in the hole with three centralizing devices. Sondes are available for use in casing from 5 1/2 to 9 5/8 inches outside diameter; the limiting diameter of the tool string is the sensor. The maximum temperature and pressure rating of the downhole equipment is 350°F and 20,000 psi.

In the uphole signal processing equipment, a differential display is used to present data transmitted from the downhole tool. The nominal inside diameter for the casing being inspected is first set into the instrument memory. Deviations from the nominal level are then recorded on film and displayed on the log.



ETT-C PROCESSING

a) LOW FREQUENCY SHIFT: F (t, μ)
b) MIDDLE FREQUENCY MEASURE: F (μ ID)
c) HIGH FREQUENCY MEASURE: F (ID)
- PROCESSING b) and c) YIELDS μ
- PROCESSING a) and μ YIELDS t

t =WALL THICKNESS
μ =RELATIVE PERMEABILITY
ID =CASING INSIDE DIAMETER

Figure 42. Diagram of modified ETS array (Smith, 1980).

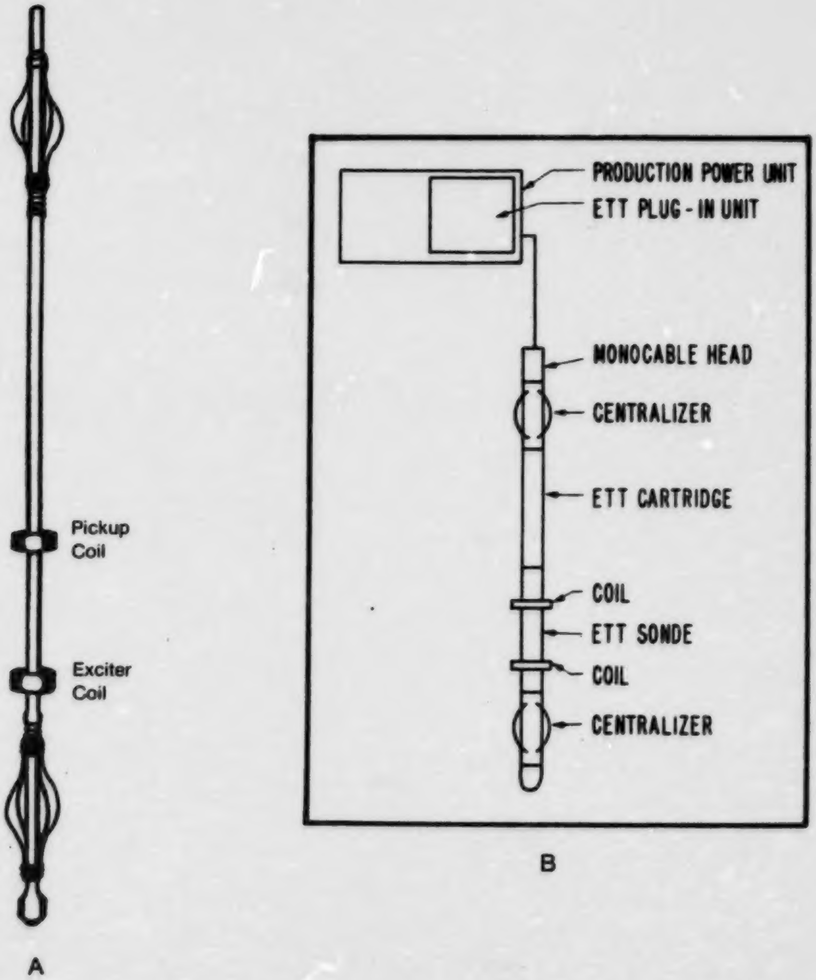


Figure 43. ETS downhole tool and diagram of an ETS logging system (A—Stroud and Fuller, 1961, B—Cotton et al., 1981).

PROCEDURES

The ETS is run much the same as the PAS in that the downhole tool is lowered down the well on a wireline, AC current is then supplied to the tool's sonde so that a magnetic field may be generated, and the tool is then pulled up the well. Normal logging procedure would call for an in-hole run at a speed of about 150 feet/minute. The ETS may be run as a base log either before or after perforating, since the wellbore fluid has no effect on the log. The tool works equally well in gas, air, water, or oil.

Prior to running the tool in the well, the tool is calibrated by recording an "air reading" with the tool suspended above the wellhead. This is the recorder response to zero casing wall thickness. As the tool is lowered into the well and the casing wall thickness is recorded, the recorder pen on the uphole logging instrumentation moves from left to right on the strip chart.

The coils on the logging sonde must be adjusted so that the flux lines generated by the exciter coil just reach the pick-up coil, and not so far away that the signal received is too weak to be detected. This has required an exciter coil to pick-up coil spacing of two to three times the casing diameter. Thus, for 7" and 9 5/8" casing, spacings of 17.6" and 21.6" respectively would be necessary (Cotton et al., 1981).

Experience indicates that the ETS is of great value in determining the extent and rate of casing damage if periodic surveys are made at regular time intervals, beginning with a base log recorded at the time of completion of the well. With a base log for comparison, corrosion and other casing damage can be detected when as little as three to five percent of the original casing thickness has been affected. With this method of early detection, it is possible to take remedial action before serious problems develop in a well. This also allows for more accurate methods of interpretation, since anomalies due to casing mill tolerances will be detected by the survey and recorded on the base log.

INTERPRETATION

The ETS can be a valuable tool in isolating corroded or otherwise damaged intervals of well casing. However, several points must be kept in mind when interpreting ETS logs.

Because phase shift is dependent on the magnetic and electrical properties of the casing, it is difficult to positively distinguish whether a log anomaly is due to loss of metal from the casing or to a change in casing properties. Running ETS logs on a time-lapse basis assumes that the magnetic and electrical properties of the casing are constant with respect to time as the casing performs its function in the well. Reductions in the phase shift over time, then, reflect a loss of metal. However, many wells have never had a baseline log run. This poses a major obstacle in the evaluation of information from any ETS log run on those wells.

The ETS measures the changes in metal mass by responding to phase shifts in an induced magnetic field between two coils. It indicates only possible total metal loss and therefore cannot differentiate between interior and exterior casing damage.

It is difficult to place an accurate quantitative scale on the log because of mill tolerances inherent to the casing manufacturing process. Zero metal thickness is determined from an air reading, allowing for calibration of the instrument. If casing sizes and weights are known prior to running the ETS, an "average" reference joint can be established by the log analyst. By using this reference level as the value for nominal wall thickness, an approximate linear scale can be applied to the log. The log displayed is linear with respect to average wall thickness for uniform sections of casing longer than the length of investigation, which is approximately the distance measured between the exciter coil and the pick-up coil.

Magnetic permeability and electrical resistivity of the well casing also affect the ETS log. Differential stresses placed on casings can alter magnetic permeability with time and can thus affect log response. Generally an increase in casing magnetic permeability increases the response of the log and an increase in casing electrical resistivity decreases log response.

With the modified ETS, it is possible to determine true wall thickness, because this survey does not depend on casing magnetic permeability or metal resistivity. Because the mid-frequency measurement of this log is a function of both magnetic permeability and inside diameter, processing the mid-frequency and high-frequency data together yields a measurement of magnetic permeability. This permeability value processed with the low-frequency phase-shift data enables the interpreter to compute true wall thickness. Thus, the multiple-coil, multiple-frequency approach enables measurement of differential inside diameter, magnetic permeability and casing thickness. This not only eliminates dependence on magnetic permeability but also adds a sensitive inside diameter measurement to the ETS.

COST

The cost of conducting an electromagnetic thickness survey is dependant upon the many general pricing variables as outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Table 14. Refer to Table 7 for a listing of companies surveyed which perform this service.

TABLE 14. TYPICAL DEPTH AND LOGGING CHARGES FOR ELECTROMAGNETIC THICKNESS SURVEYS

Depth Charge	Low	High
per foot	$0.29	$0.30
minimum	$580.00	$600.00

Logging Charge	Low	High
per foot	$0.29	$0.30
minimum	$580.00	$600.00

ADVANTAGES AND DISADVANTAGES

The ETS offers several advantages in mechanical integrity testing. The primary advantage is that it offers the only method of detecting corrosion or other defects on the outer string of a double (concentric) string of casing. This could have great benefits in wells which must utilize multiple casing strings, for there are no other surveys available which can accomplish this.

There are several disadvantages to using the ETS in mechanical integrity testing. Because of the limited resolution of the tool, the smallest defect it can detect is approximately one inch in diameter. Also, it cannot discriminate between inner wall and outer wall defects. The PAS must be used in conjunction with the ETS to resolve these two problems.

One of the other major disadvantages of the standard ETS is that it is dependent on the magnetic and electrical properties of the casing being surveyed. Therefore, it is difficult to positively distinguish whether a log anomaly is due to a loss of metal from the casing or to a change in casing properties. The availability of a baseline log, run immediately after the installation of the well, would alleviate this problem. However, many older wells have never had a baseline log run, so evaluation of information from any ETS log run in these wells is difficult. A modified ETS is available to eliminate this problem, however it is offered by only one well servicing contractor.

ETS logs cannot be run in tubing due to the large outside diameter of the tools used to produce the log. Tubing must be removed from the well prior to conducting this type of survey.

EXAMPLES

Figure 44 is a portion of the ETS log run in a well in the San Juan Basin, New Mexico. A possible pit or hole is indicated at 735

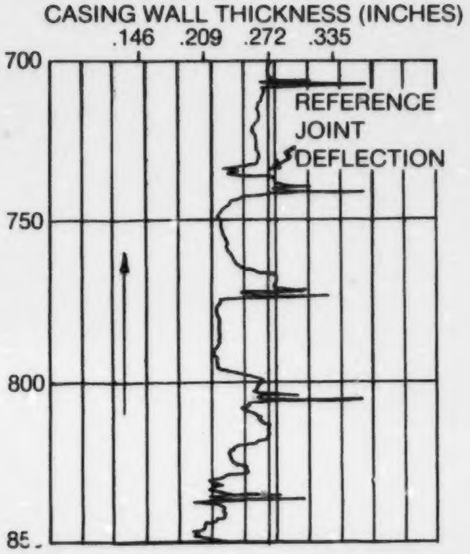


Figure 44. Casing inspection log of a portion of a well in the San Juan Basin of New Mexico (750-850 feet) (Edwards and Stroud, 1963).

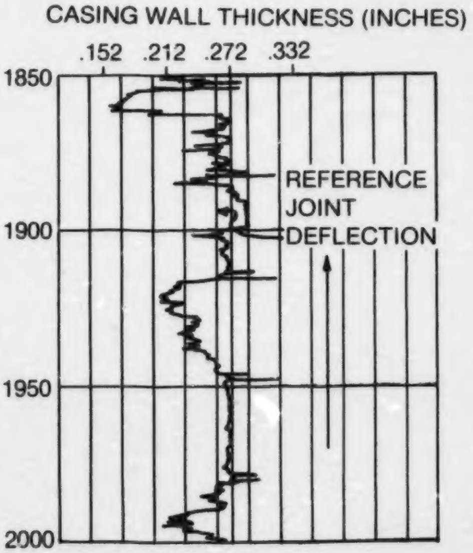


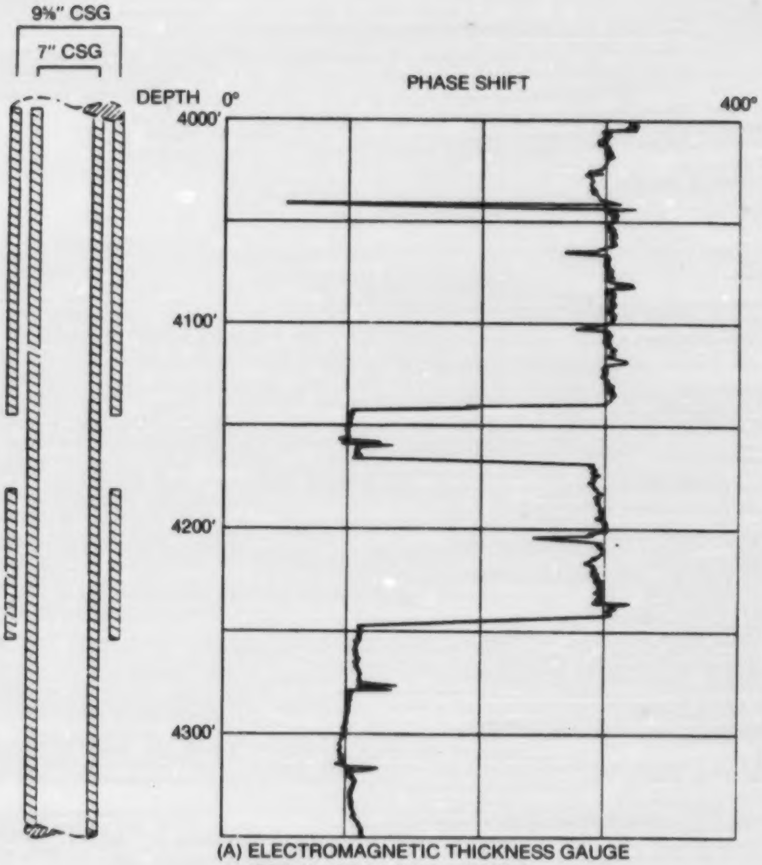
Figure 45. Casing inspection log of a portion of a well in the San Juan Basin of New Mexico (1,850-2,000 feet) (Edwards and Stroud, 1963).

feet and probable extensive corrosion is evident from 820 to 850 feet. A possible hole or pit can also be seen at 847 feet. As a result of the evident extent of corrosion in this well, a new string of casing was run and the well recompleted (Edwards and Stroud, 1963).

Figure 45, the log of a well in the same township as that illustrated in Figure 44, indicates extensive corrosion in the interval from 1100 to 2100 feet. A maximum metal loss of 42 percent indicated in the interval from 1855 to 1862 feet. The character of the log indicates extensive small pits or mottled type corrosion throughout the logged interval (Edwards and Stroud, 1963).

Figure 46 illustrates the capability of the ETS log to detect problems in concentric casing strings. This is an extreme case where a 9 5/8" casing has parted completely and dropped down the hole behind a string of 7" casing. The section of log between 4140 feet and 4170 feet is the phase shift corresponding to a single string of casing and is identical to that found below 4250 feet (single string of 7" casing). A high-resolution caliper survey run in the 7" casing indicated the casing tube in good condition.

Figure 47 is an example of a rip in the casing wall of a well, noted on both a pipe analysis log and an electromagnetic thickness log. The pipe analysis log shows the beginning and end of the rip, reacting at a point of change in the amount of metal which causes a change in the flow pattern of the induced magnetic flux. In the interval between the top and bottom of the rip, the damage is consistent and the flux does not change appreciably. The electromagnetic thickness log reacts to the total damaged area because of the different physical principle involved in the measurement. The two tools in combination clearly locate and define the anomaly, whereas either one used alone could not do the job (Cuthbert and Johnson, 1974).



(A) ELECTROMAGNETIC THICKNESS GAUGE
(ETT-A) w/21.6" COIL SPACING

Figure 46. Field application of 26'6" coil spacing ETT-A sonde in concentric string of 7" x 9⅝" casing (Cotton et al., 1981).

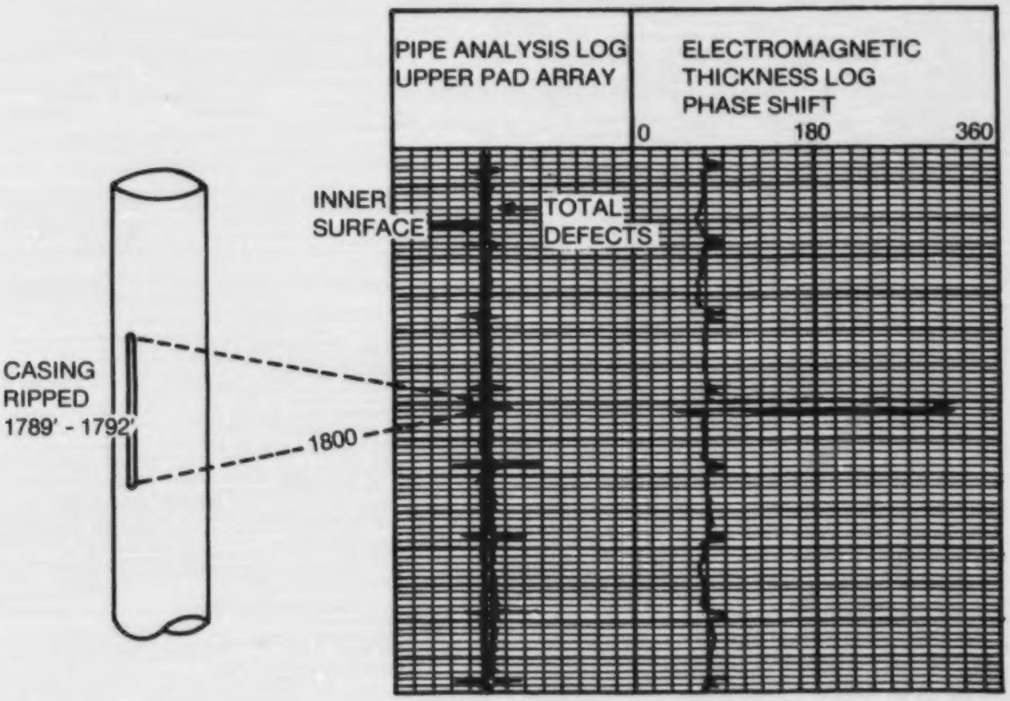


Figure 47. Indications of a casing rip in pipe wall away from any collars (Cuthbert and Johnson, 1974).

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SECTION 12

CALIPER LOGGING

SYNOPSIS

Caliper logging was introduced as a commercial well service for logging open holes in 1938 (Hilchie, 1968). The application of caliper logging to cased holes, where it is useful as a tool for determining the mechanical integrity of injection well or production well casing or tubing, is somewhat more recent. However, little effort has been made to update the literature regarding the more modern applications of caliper logging. Several significant refinements of the technique have resulted in caliper logging being one of the most accurate means of locating defects in casing or tubing.

When used in a cased hole, the caliper log is a continuous profile of the casing or tubing's inside diameter with depth. Cased-hole calipers can be used for several purposes, including:

1) locating breaks in parted casing or tubing;

2) locating distortions in casing due to partial collapse;

3) locating areas of internal corrosion;

4) locating leaks or holes in the pipe; and

5) locating paraffin deposits or mineral scaling present on the inside of casing.

Calipers used in cased holes are of three general types - mechanical, electronic, and acoustic. Mechanical calipers use finger-like arms or feelers to contact and measure the inside surface of casing or tubing, producing a continuous profile of the inside diameter with depth. Two different varieties of mechanical calipers are available - those with six or fewer arms (low-resolution calipers generally used in open-hole applications) and those with from 20 to 64 arms (high-resolution calipers). Calipers with six or fewer arms can generally be used in cased holes only to determine the shape of the casing in cross section, to detect major distortions in the diameter of the casing. This is useful in mechanical integrity testing, as the presence of a distorted casing may indicate casing damage in the form of splits or breaks. Calipers with from 20 to 64 arms can be used in cased holes to detect minor casing anomalies, such as pitting and small holes, and thus are better suited to mechanical integrity testing of injection wells. These calipers can be used in tubing with 1 1/2" to 4" inside diameter or in casing with 4 1/2" to 13 3/8" inside diameter. Tools available from well servicing contractors can be used in wells with pressures and temperatures to 10,000 psi and 350°F respectively. Logging speeds of 90 to 100 feet per minute are possible with the high-resolution mechanical caliper.

Electronic calipers use an electronic principle to measure the inside diameter of casing. This type of caliper was introduced in 1966 specifically to complement the electromagnetic casing inspection log (Edwards and Stroud, 1966). It is described in more detail in Sections 10 and 11, which describe two different types of electromagnetic casing inspection surveys.

The acoustic caliper log is produced by the travel-time dependent rather than the amplitude-dependent output of the borehole televiewer (Keys, 1981). The travel time of an acoustic pulse generated by the downhole tool and reflected off of the casing wall is recorded, prodiving an extremely high resolution log of hole diameter. This method is discussed in greater detail in Section 14.

Because both electronic and acoustic calipers are discussed in other sections of this report, only mechanical caliper logging will be discussed here.

PRINCIPLES

The principle of a mechanical caliper log is very simple. This log employs a tool with feeler arms which extend from the body of the tool to contact the interior wall of whatever pipe the tool is being run in (either tubing or casing). The feeler arms act as small calipers, each measuring the inside diameter of the pipe at the point at which it contacts the pipe's inner surface. As the tool is run in the well and the full length of pipe is surveyed, each feeler arm produces a signal which is recorded at the surface. Taken in combination, the measurements made simultaneously by all of the feeler arms produce a representation of the full inside circumference of the pipe. Compared against the expected inside diameter of the pipe as installed in the well (to an accuracy specified by the American Petroleum Institute for oilfield tubular goods), the log can show areas where defects occur in the pipe. The recorded log indicates either the actual amount or a percentage of remaining wall thickness at every point along the tubing or casing.

EQUIPMENT

The construction details of mechanical caliper tools differ depending upon the manufacturer or the well service contractor. It is possible, however, to generalize some of the basics of equipment design.

The mechanical caliper tool consists of a central shaft fitted with from two to six hinged arms (low resolution type) or from 20 to 64 arms (high resolution type). In the former tool, the central shaft is enclosed by a rubber, oil-filled chamber in which the hinged arms are connected to a potentiometer that measures changing resistance. The arms fold against springs into the side of the shaft when fully retracted, and rest against the inside of the casing when fully extended.

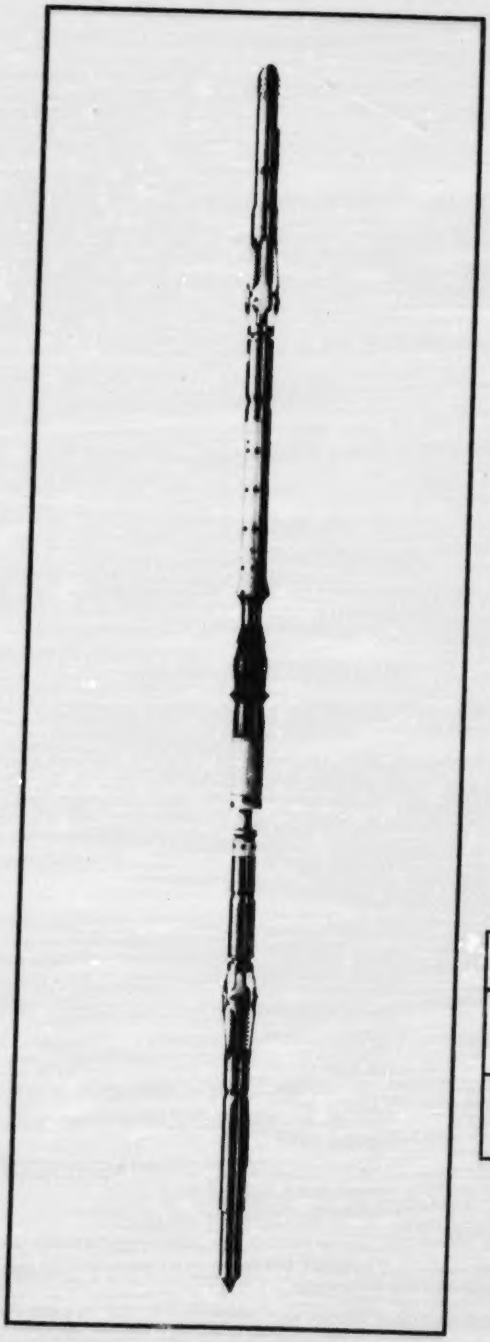
In the high-resolution-type caliper the feelers, which are either spring loaded or motor-driven, retract into the body of the shaft when the tool is not in use, and extend to contact the inside of tubing or the casing when the tool is in use.

Low-resolution calipers for use in cased holes are available in sizes from 1 1/2" outside diameter to 4" outside diameter to measure casing from 4" diameter to 60" diameter. Two-arm, three-arm, four-arm, and six-arm calipers are available.

High-resolution calipers for use in tubing are available in sizes from 1 1/2" outside diameter to 3 1/32" outside diameter to measure tubing from 2" diameter to 4" diameter (Figure 48). High-resolution calipers for use in casing are available in sizes from 3 5/8" outside diameter to 11 5/16" outside diameter to log 4 1/2" diameter to 13 3/8" diameter casing (Figure 49). The number of feeler arms on these tools increases with the diameter of the tool, from 20 to 30 feelers on the tubing caliper to 40 to 64 feelers on the casing caliper. The width of the feeler arms is generally less than one-tenth of an inch and the feeler tips are less than one-half inch apart at the outside when extended. The feeler arm section is generally in the middle of the tool. These tools are all rated consistently at 10,000 psi and from 300°F to 350°F depending on the manufacturer.

Most low-resolution calipers do not employ centralizers. They are allowed to freely orient themselves and pass through all types of casing deformities. On the other hand, high-resolution tools do utilize centralizers to maintain the caliper tool in positive axial alignment in the casing or tubing to ensure the accuracy of the measurement. The centralizers are located above and below the section of the tool containing the feeler arms.

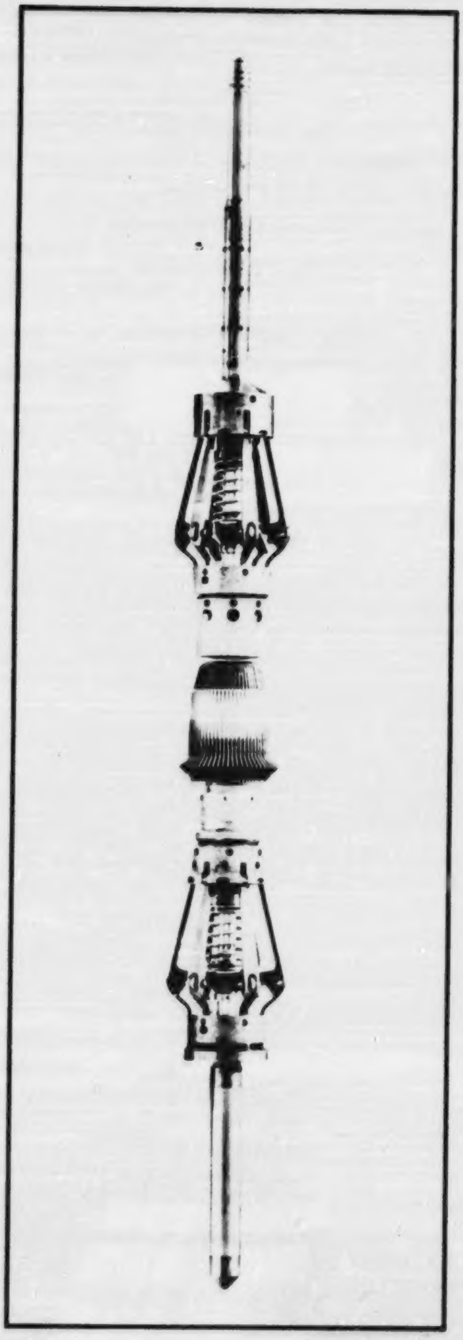
An amplifier is located between the feeler arms and the upper centralizer in the high-resolution tool. The amplifier boosts the electrical signal generated by the movement of the feeler arms in response to changes in inside diameter of the tubing or casing.



Sizes of Tubing Profile Calipers

O.D. of Tubing	Number of Feelers	Tool Diameter
2"	20	1½"
2 1/16"	20	1½"
2⅜"	26	1¾"
2⅞"	32	2 3/16"
3½"	44	2 11/16"
4"	44	3 1/32"

Figure 48. High resolution tubing caliper tool (Dialog, Inc. product literature).



Size of Casing Profile Calipers

O.D. of Casing	Number of Feelers	Tool Diameter
4½"—6"	40	3⅝"
6⅝"—7⅝"	64	5⅜"
8⅝"—9"	64	7¼"
9⅝"	64	7¾"
10¾"	64	8¼"
11¾"	64	9 9/16"
13⅜"	64	11 5/16"

Figure 49. High resolution casing caliper tool (Dialog, Inc. product literature).

PROCEDURE

To produce a log with the low-resolution caliper tool, the tool is lowered to the bottom of the well with the arms retracted (with the exception of the bowspring-type caliper). When the tool reaches the bottom of the well, the arms are released so that they contact the wall of the well casing and the tool is pulled up the hole. As the pressure from the arms on the central chamber changes with the varying diameter of the casing, the potential drop across the potentiometer is measured and recorded at the surface.

To produce a log with the high-resolution caliper tool, the tool is lowered down the tubing or casing on a standard wireline with its arms retracted. When the tool reaches the bottom of the survey depth desired, the feeler arms and centalizers are released by either a spring-loaded or motor-driven mechanism and the tool is raised up inside the well. As the tool is brought up the well, the caliper feelers continuously contact the casing or tubing wall, measuring the minimum and maximum diameter of the internal wall of the casing or tubing. The arms are free to move independently to conform to the condition of the casing wall, extending in places where the casing has a large diameter (i.e. where corrosion has pitted the casing or where holes in the casing exist), and retracting in places where the casing has a smaller diameter (i.e. where scale has been deposited or where the casing has partially collapsed). The large number of arms on the high-resolution caliper ensures the detection of even very small irregularities in the casing or tubing wall.

This tool produces a log which is a record of variations in casing or tubing diameter with depth. The tool can be closed and reopened from the surface allowing for any number of log repeats. This procedure allows repositioning of the tool for the detection of casing defects that are even smaller than the distance between the feeler arm tips.

The inside diameter of the tubing or casing in which the caliper is run is determined by the feeler arm that extends the furthest from the axis of the caliper tool. The movements of the individual arms of the tool are converted to electrical signals. The feeler which penetrates the greatest depth into any irregularity in the wall of the tubing or casing generates the most intense electrical signal. The signal is amplified within the tool, transmitted to the surface via the wireline, and recorded on standard surface equipment.

The instruments used in the caliper log, both the downhole tool and surface recording equipment, are calibrated before and after each logging run. It is possible to obtain a fast, accurate record of casing or tubing diameter with the high-resolution caliper. Logging speeds of 90 to 100 feet per minute are reported (Dia-Log, Inc., product literature).

INTERPRETATION

Interpretation of the tubing caliper log is somewhat different from that of the casing caliper log. The tubing caliper log, which is available from only one well service company, is a record of wall penetration of tubing defects in percent (Dia-Log, Inc., product literature). Nominal inside diameter thus equals zero percent wall penetration, and nominal outside diameter is 100% wall penetration. The tubing is graded on the log in 5% increments of the nominal wall thickness to show the maximum penetration or wall loss recorded. This measurement is a function of American Petroleum Institute specifications for new tubing, which allow the nominal outside diameter to vary by ± 0.031 inch and the nominal wall thickness to vary by -12.5%.

The casing caliper log (Dia-Log, Inc., product literature) indicates remaining wall thickness in fractions of an inch. The accuracy of the remaining wall thickness on this log is a function of the American Petroleum Institute specifications for new casing, which allow the nominal outside diameter to vary by ± 0.75%.

Another caliper log (Gearhart-Owens, Inc., product literature) is a record of both minimum detected internal diameter, at a scale of 0.1" per chart division on the strip chart, and maximum detected internal diameter, at a scale of 0.05" per chart division. The minimum wall recording shows actual wall loss, while the maximum wall recording is represented as remaining wall thickness, including any buildup attributed to scale or other restrictions on the pipe's inside surface (Figure 50).

COST

The cost of conducting a caliper survey is dependant upon the many general pricing variables as outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Table 15. Refer to Table 7 for a listing of companies which perform this service.

TABLE 15. TYPICAL DEPTH AND LOGGING CHARGES FOR CALIPER LOGGING

	Low	High
Depth Charge		
per foot	$0.23	$0.33
minimum	$500.00	$660.00
Logging Charge		
per foot	$0.30	$0.33
minimum	$580.00	$660.00

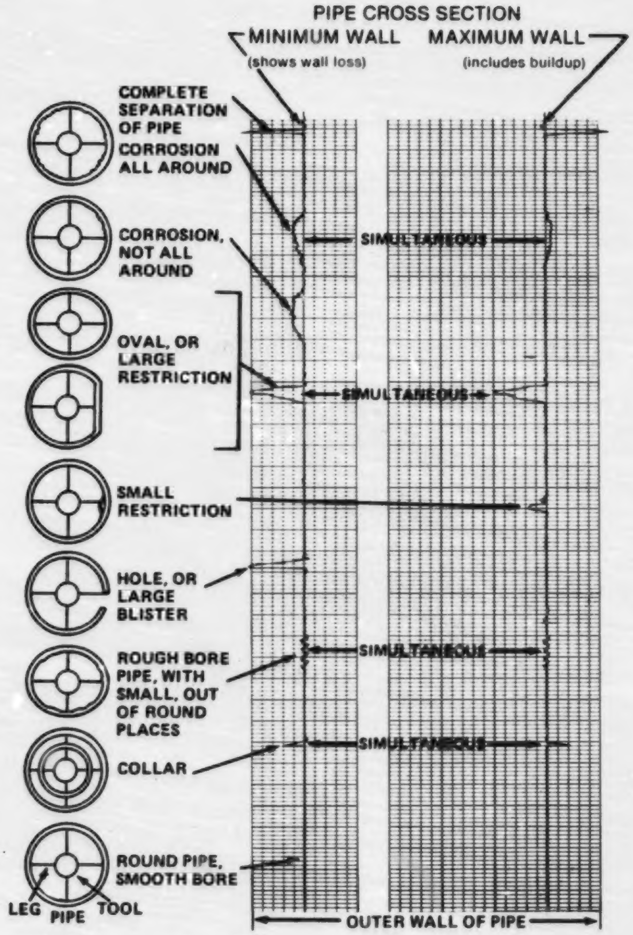


Figure 50. Standard casing and casing anomalies recorded by a caliper logging tool (Gearhart-Owens, Inc. product literature).

ADVANTAGES AND DISADVANTAGES

The primary advantage of high-resolution mechanical caliper logging in mechanical integrity determinations is that it provides a very accurate record of the condition of the inside of a string of tubing or casing. High-resolution caliper logs can be run in both tubing and casing, at relatively high logging speeds. Mechanical calipers have several weaknesses. Perhaps the greatest weakness is the inability of the tool to reveal the presence of small-diameter, drill-hole-like pits or holes in the casing or tubing (NL McCullough, Inc., product literature). Such holes may escape being located even by high-resolution calipers, because the feeler arms are located approximately one-half inch apart. Unless the caliper is reoriented and a repeat run made in the well, holes just smaller than one-half inch in diameter may go unrecognized as the tool is raised up the hole.

In addition, it is difficult to locate some vertical splits or hairline cracks in casing because of the method in which the caliper tool is operated. At least one well service company offers a tool to detect splits in tubing or casing as an accessory to the caliper. The split detector, which functions like a magnetic casing collar locator, is designed specifically to detect and log vertical cracks or splits in tubing or casing (Dia-Log, Inc., product literature). In practice, the split detector is used to log going down the well, while the caliper log is made going back up the well. This allows for a complete inspection of both the wall thickness and casing splits in one run of the tool string in the well.

In wells with tubing and packer completions, it is possible to log the tubing independently of the casing. However, if it is desired to log the casing in addition to the tubing, the tubing must be pulled before the casing can be logged. This can be a lengthy process, and it generally necessitates the installation of a new packer. The high-resolution mechanical caliper is only available from a limited number of well servicing companies.

EXAMPLES

Figure 51 illustrates a tubing profile caliper tool and the log produced by running the tool in a well having a variety of mechanical defects, including moderate corrosion pitting, holes and severe corrosion pitting, and rod scores on the inside of the tubing. Tubing joints are recognizable by their distinctive signal (roughly corresponding to nominal outside tubing diameter). Baseline on the log is nominal inside diameter; defects on the inside of the tubing are recognized by departures from this baseline. Corrosion pitting and holes are indicated by deflections to the left, while scale buildup or partial collapse would be indicated by deflections to the right. The results of a log produced by a companion tool, the split defector, are also included on Figure 51. Log deflections due to two vertical splits are shown.

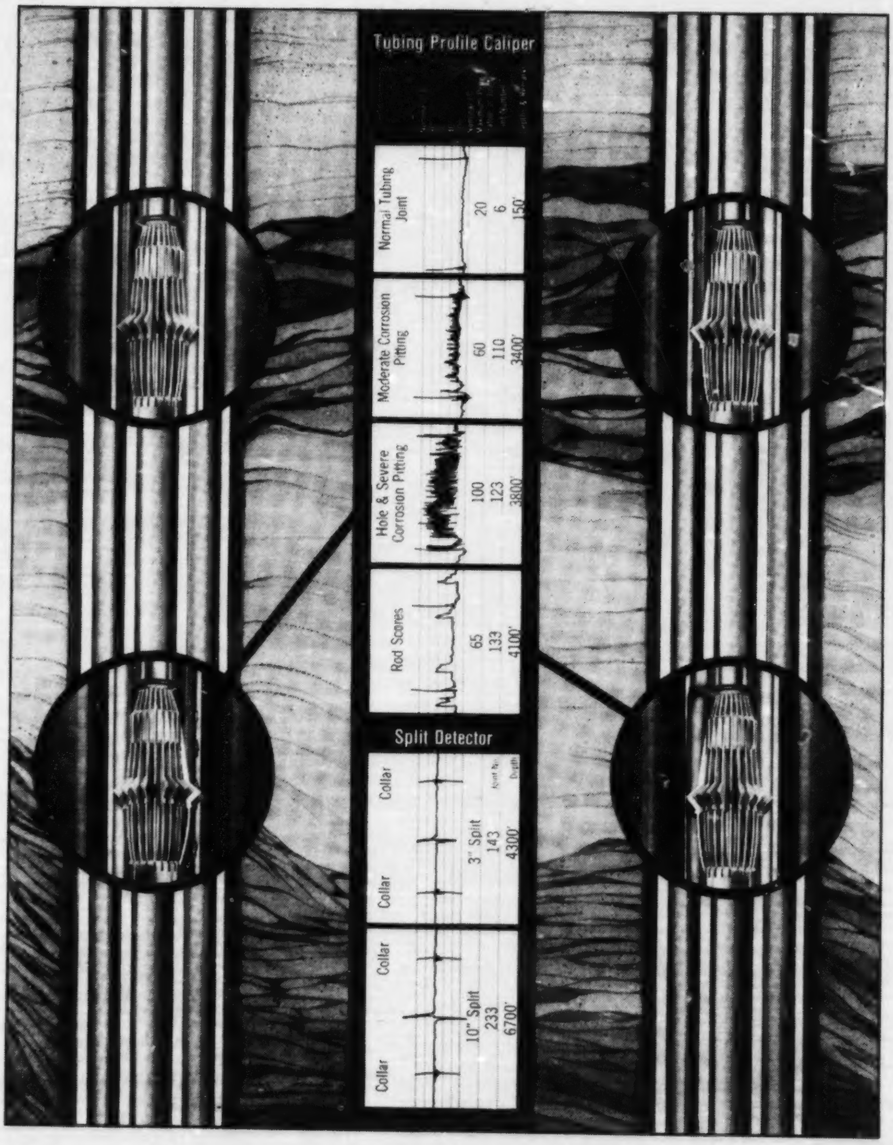


Figure 51. Example of a tubing profile caliper (Dialog, Inc. product literature).

Figure 52 illustrates a casing profile caliper tool and the log produced by running the tool in another well, showing log response to a variety of downhole conditions. A casing weight change, illustrated by a shift in the baseline on the log, is indicated at 250 feet. At 1400 feet, a hole and severe corrosion pitting is indicated by an intense concentration of log deflections. Drill pipe wear at 2600 feet; split, parted and damaged casing at 3300 feet, 4400 feet and 7000 feet respectively, and perforations at 9600 feet also produce recognizeable log deflections.

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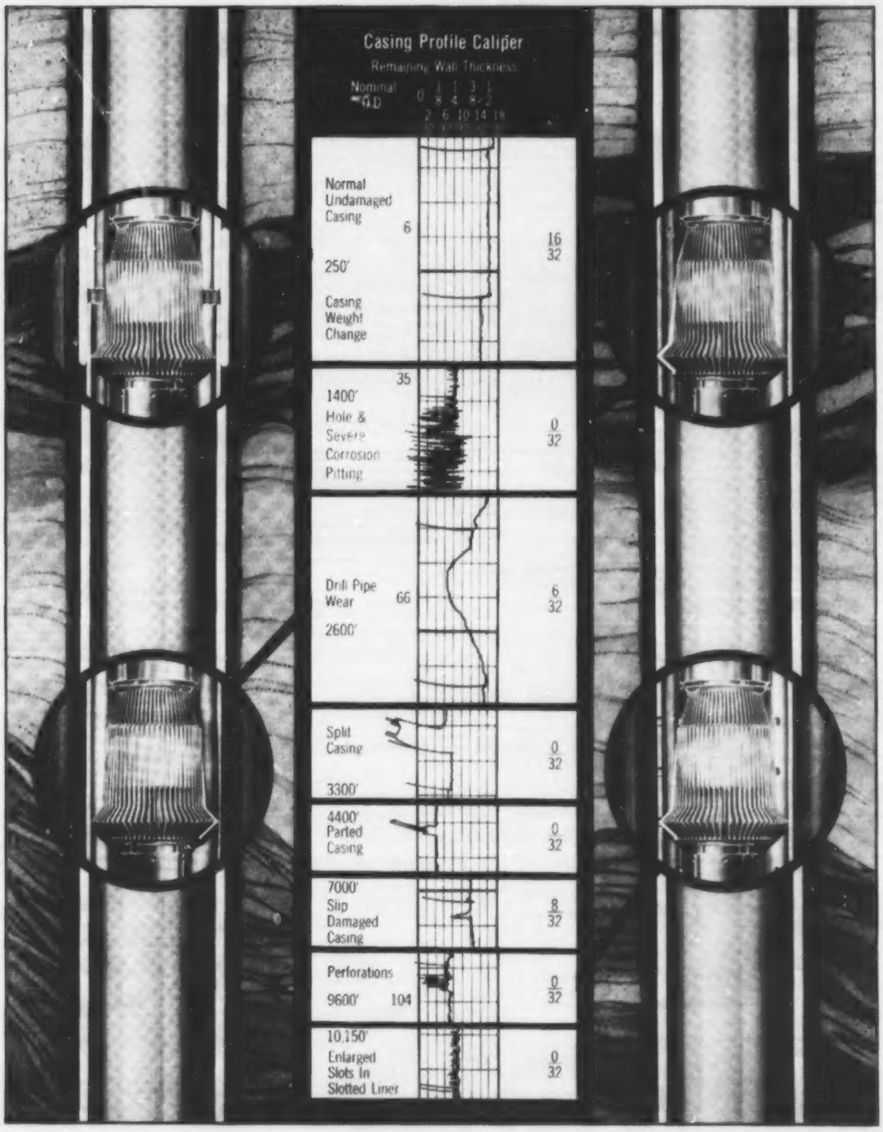

Figure 52. Example of a casing profile caliper (Dialog, Inc. product literature).

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SECTION 13

BOREHOLE TELEVISION

SYNOPSIS

The borehole television (TV) survey provides a continuous photographic log of the inside surface of well casing. The borehole TV survey reports on the condition of the casing as viewed from the inside; the condition of the outside casing surface and the condition of the cement behind the casing cannot be determined from this log.

When logging with a borehole TV system, a miniature television camera is lowered into the well. A light source illuminates the inside of the casing and the resulting television picture is transmitted back up to the surface for recording and viewing. As the camera is lowered into the well, a continuous photographic log is obtained. The camera may be slowed or stopped at any depth and the focal length changed on the lens to magnify a particular problem for close examination.

PRINCIPLES

The principle behind the borehole TV survey is similar to that of a closed circuit TV system. An object reflects light rays back toward the camera and the reflected rays of light enter a lens. As the rays of light pass through the lens, they are focused onto a light sensitive plate called a charge-coupled device (or CCD). An iris located in the lens adjusts the amount of light that strikes the CCD.

The CCD chip onto which the light rays are focused is scanned by a microscopic network of horizontal and vertical lines. The scan determines the color as well as the light intensity that strikes the area and sends a corresponding signal to an amplifier for transmission to the surface (Cheshire, 1982).

EQUIPMENT

The borehole TV logging tool consists of a miniature closed circuit TV camera, a light source and related electronic circuitry. Cameras can transmit either black and white or color pictures back to the surface. The size of the camera ranges from 2 3/4 inches to 4 7/8 inches in diameter, and from 18 inches to 24 inches in length (exclusive of the light source). Centralizers are standard equipment on all camera housings, allowing the cameras to be run in 3-inch to

36- inch tubing or casing. Standard lenses and lighting are used for a maximum hole diameter of approximately 9 3/4 inches. Optional lenses and higher intensity lighting are needed for larger holes.

The lighting source is perhaps the most important piece of equipment in borehole TV logging. Without proper lighting (and clear water in the well), it is impossible to photograph the inside surface of the well casing. Improper lighting results in "bounce back" or reflection of the light source caused by turbid water or reflection off the well casing surface, thus "blinding" the camera due to excessive light. Most color cameras are balanced according to the expected or recommended lighting requirements. The majority of color lighting systems consist of a tungsten light source while most black and white cameras utilize a quartz-halogen light source. There are a few exotic lighting sources available, but their use is limited at this time.

Light sources can either be located in an annular ring around the camera lens or hung several inches below the camera lens. Both light-source locations offer advantages and disadvantages, the discussion of which is beyond the scope of this report.

Camera housings are usually made of stainless steel and can be constructed to exceed 25,000 psi. However, the operational depth of the cameras is limited by several factors, primarily the lighting source. Standard lighting sources frequently implode (or are crushed) at excessive depths. In addition, the power requirements for the light source limit the operation of the cameras to approximately 8,000 feet due to the fact that the electrical resistance of the cable is too great below this depth. The cable resistance also limits the depth the signal from the camera can be transmitted back to the surface. Thus, for all practical purposes, camera operation is limited to depths of 8,000 feet and most systems will not operate to this depth (Davis and Fleniken, 1980).

Borehole temperature also limits the camera depth. A temperature of approximately 175°F is generally the maximum operating temperature (Mullins, 1966). Ice packs and thermal bottles can extend that limit, but only for a short period of time (1-2 hours).

Surface support equipment is elaborate. The signal from the camera is sent to the surface via a 12, 16 or 32- conductor cable not found on a standard logging truck. At the surface, the signal is split; one signal goes to a Video Cassette Recorder (VCR), the other to a TV monitor. The VCR is generally a standard, high-quality video recorder on which the camera signal is recorded so that a permanent record of the log exists and can be played back at a later date.

When the camera is in operation, the conductor cable passes over a measuring sheave. The sheave sends a depth indicator signal to the VCR and the monitor. In surveying deep wells, a sophisticated measuring sheave that will correct for the stretch potential of the cable may be used. Depth readings are overlayed and recorded simultaneously with the camera signal. Other data such as the date or job number can also be recorded by overlaying the data on the signal. An audio track is usually available for audio dubbing either during or after the logging operation.

The TV monitor is a standard TV screen. It is used to monitor the quality of the log as well as the survey itself. On systems so equipped, the tool can be slowed, stopped, re-focused or adjusted to view an area of particular interest.

PROCEDURES

To run a borehole TV survey, injection into the well must be stopped and the injection tubing removed from the well. The well then must be thoroughly flushed with a clear fluid. This step is very important, because the quality of the log hinges on the quality of the flushing job. The well is then shut-in for an hour or two to allow the fluid to stabilize and particulate matter to settle (Davis and Fleniken, 1980).

If flushing the well fails to clear the turbidity from the water, the well fluid may be treated with a flocculent additive. One gallon of feric floc and one gallon of hot lime for each 1,000 gallons of water contained in the well has been successfully used to flocculate and clear wells. The solution is mixed at the surface and injected into the well. The well then must stand for 12 to 24 hours to allow for settlement of the floc (Jensen and Ray, 1965).

Once the fluid in the well is of an acceptable clarity, the camera is lowered into the well on a wireline to the starting point of the survey. The system is checked and the depth indicator is synchronized. As the log begins, the camera is lowered down into the well. Logging speed varies throughout the survey because the camera can be stopped or slowed at any point so that a more detailed view of the casing can be gained. Logging speeds generally range from 0-25 feet per minute, but little is seen at the higher speed. The resulting VCR tape can also be slowed while being played back at a later date.

If the well has a layer of oil floating on top of the water standing in the well, the camera lens is usually coated with a detergent paste. As the camera passes through the floating oil, the detergent prevents the oil from fouling the lens. The detergent coating washes off as the camera is run up and down in the water below the oil layer (Jensen and Ray, 1965).

INTERPRETATION

The interpretation of all photographic logs is difficult to the untrained viewer. The low angle of viewing and the wide-angle lenses that are typically used require a period of orientation (Huber, 1982).

After the survey is run, the log is presented on a TV monitor screen and can be slowed or stopped by controlling the VCR playback unit. Because the depth of the camera is always shown on the screen along with the image, depths to problem areas are known. Casing collar locations are easily seen in most wells and are used for correlating depth and location of problems.

Turbid or murky water will inhibit accurate interpretation as will scale on the inside of the casing. Turbid water will reflect light rays back to the camera and cause the camera to be "blinded" by excess reflected light. The inside surface of the casing can also cause camera blinding by reflecting light rays from an improperly positioned light source (Davis and Fleniken, 1980).

COST

Davis and Fleniken (1980) have estimated that costs for borehole TV logging are in the same order of magnitude as other types of geophysical logging. Table 16 contains a price list showing the average cost in the United States in 1980 dollars.

TABLE 16. TYPICAL CHARGES ASSOCIATED WITH BOREHOLE TELEVISION SURVEYS

Equipment Charge	
8 hour minimum	$750.00
Overtime	250.00/hr.
Depth Charge	
0 - 1000 ft.	Minimum
1000 - 2000 ft.	$0.30/ft.
2000 - 3000 ft.	0.40/ft.
Below 3000 ft.	0.60/ft.
Video Tapes	
1/2" 2 hr.	$75.00
3/4" 60 min.	100.00
Standby	
With crews and equipment	$250.00/hr.
Without crews	50.00/hr.
Mileage	
Portal to portal	0.80/mi.

As Davis and Fleniken (1980) note, other charges for the rig and auxiliary equipment and filtration equipment, pumps and trucking to process the water in the well to an acceptable clarity, are also associated with television logging. These costs may be four to five times the costs of the logging equipment. Davis and Fleniken (1980) estimate that, with proper equipment scheduling and preplanning, a 4000 foot well can be logged for about $6000.

ADVANTAGES AND DISADVANTAGES

There are several distinct advantages in using a borehole TV survey. The most obvious advantage is the fact that a first-hand view of the problem is obtained from the log. Visual inspection facilitates the understanding of the problem and subsequent remedial work. Also, because the log is recorded on a video tape, it can be played back at a later date or compared with another TV survey or other logs made at an earlier date. Photographs of any problem areas can be taken from the TV monitor by a polaroid camera or a 35 mm camera for detailed study or documentation.

The biggest disadvantage of borehole TV logging is that the injection tubing must be removed from the well so that direct visual contact with the inside surface of the casing is obtained.

Another problem with the use of borehole TV and other photographic methods is that the fluid in the well must be kept relatively clear. A five-inch casing holds approximately one gallon of fluid per foot of casing. Proper flushing techniques may require 2 to 3 times the well's volume of good quality fluid (usually water) to be circulated in or injected into the well prior to logging.

Another disadvantage to photographic logging is the temperature restriction imposed by either the film or the equipment. Also, the borehole TV survey must be run by a specialized contractor and the equipment is not readily available for logging injection wells in all areas of the country. This may preclude the use of borehole TV logging in some areas.

All photographic methods only report on the condition of the inside surface of the casing and a leak may not be obvious in corroded casing. No method of determining channeling or fluid migration behind the casing is available.

EXAMPLES

Figures 53 through 58 (from Davis and Fleniken, 1980) illustrate various downhole problems in wells. Figures 53 through 56 are a series of photographs of the borehole TV monitor from the logging of a single well, showing a progression of well casing damage; Figures 57 and 58 are from logs of two other wells. As these figures illustrate, it is possible to visually recognize a wide variety of problems, from

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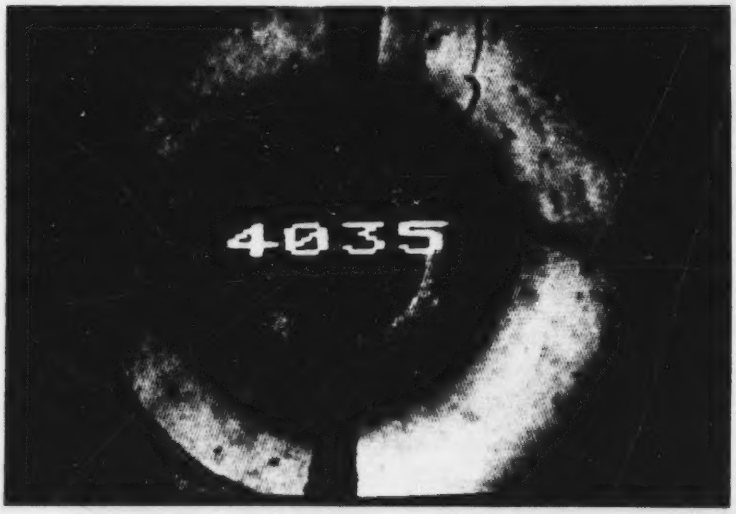

Figure 53. Downhole picture of cracked casing (Davis and Fleniken, 1980).

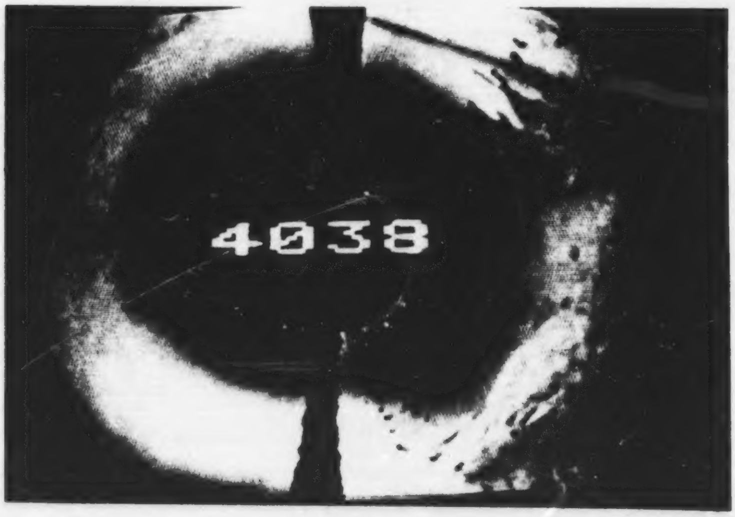

Figure 54. Downhole picture of casing damaged during a fishing job
(Davis and Fleniken, 1980)

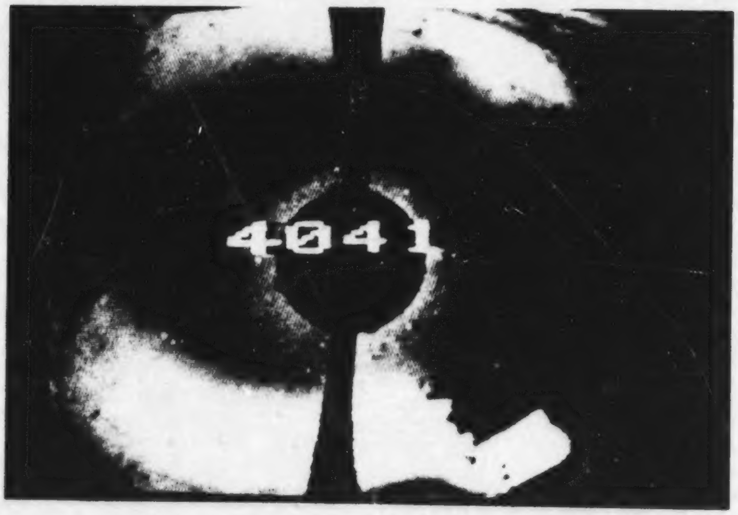

Figure 55. Downhole picture of damaged casing and resulting sidetrack (Davis and Fleniken, 1980).

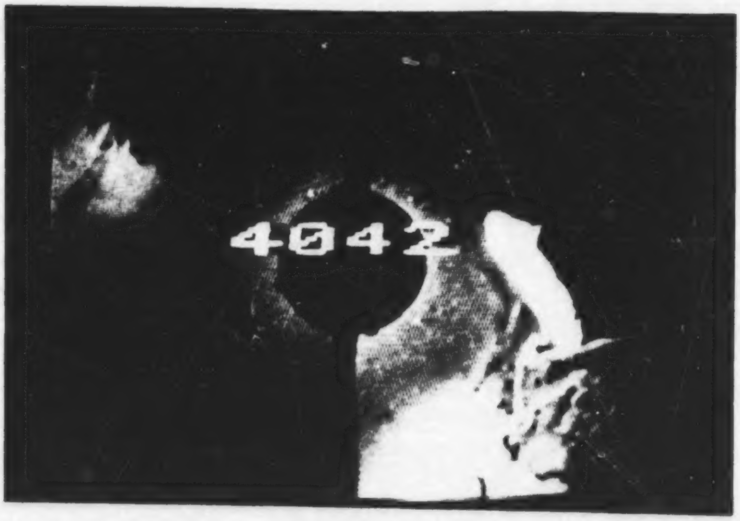

Figure 56. Downhole picture of damaged casing and resulting sidetrack at different depth (Davis and Fleniken, 1980).

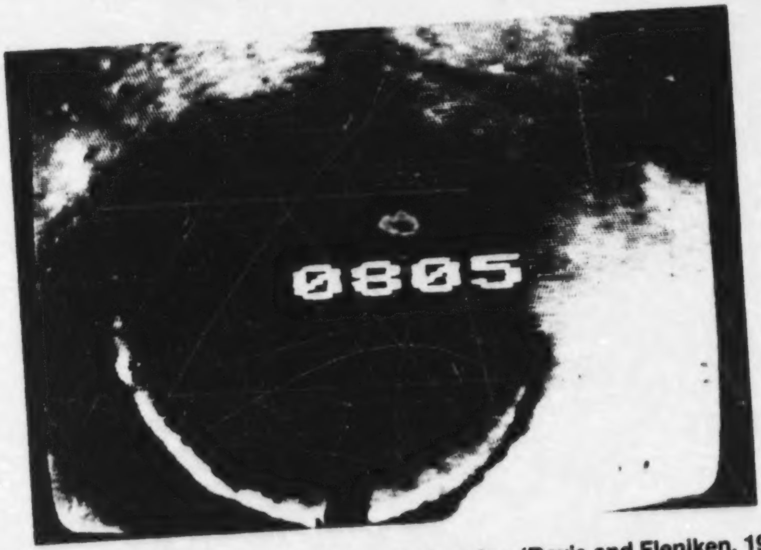

Figure 57. Downhole picture of separated casing (Davis and Fleniken, 1980).

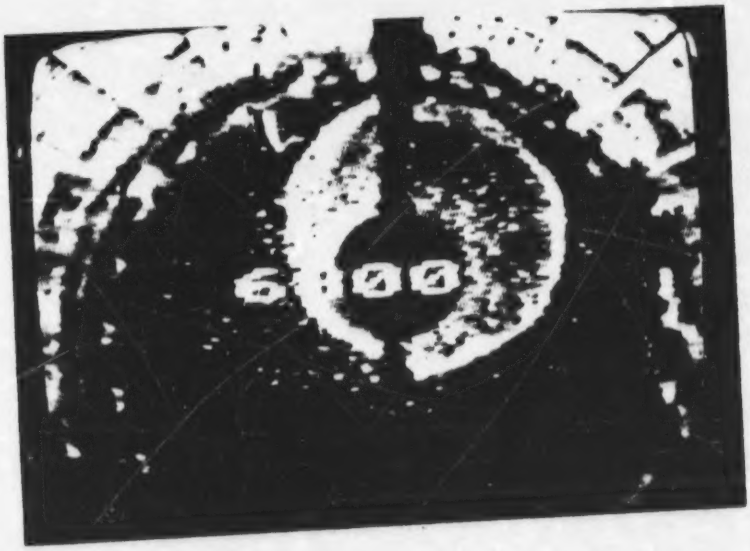

Figure 58. Downhole picture of separated tubing inside screen (Davis and Fleniken, 1980).

split, cracked or otherwise damaged casing to separated casing or tubing. On each photograph of the borehole TV monitor appears the depth that the downhole camera occupies in the well.

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SECTION 14

BOREHOLE TELEVIEWER

SYNOPSIS

The acoustic or borehole televiewer (BHTV) was developed and patented in 1966 (Zemanek, et al., 1969) and has been modified to suit several specific purposes since then. The initial purpose for which BHTV was developed was the inspection of open boreholes to locate fractured zones in potential hydrocarbon reservoirs. The BHTV has since been successfully used to solve a variety of problems related to both open hole and cased hole inspection, including:

- inspection of open boreholes for vuggy porosity or fractures,
- providing a micro-caliper of borehole and casing anomalies,
- determining the dip of fractures or bedding planes,
- detecting thin, laminated shale and sand sequences, and
- inspecting casing and tubing for splits, perforations, deterioration, or collapse.

The BHTV utilizes high-frequency acoustic energy to scan and provide an image of the inside surface of either an open borehole or a cased well. The image is a representation of the borehole or casing wall as if it were split vertically and laid out flat. With the BHTV, borehole irregularities or casing defects are located simply because they are visible on the log; log interpretation in the usual sense is not performed, but experience is needed for correct interpretation. Changes in image intensity, as displayed on an oscilloscope at the surface, indicate irregularities. In an open hole, the orientation of these irregularities can be determined; in cased holes, the orientation is not known but the features can still be recorded and studied.

Casing can be inspected with BHTV in considerably greater detail than is presently possible using most other logging tools. The BHTV is able to resolve features as small as 1/32-inch in boreholes filled with water, oil, or drilling mud. In conjunction with present-day computer-enhanced signal processing, BHTV provides a very useful tool in inspecting casing or tubing for the purpose of determining the mechanical integrity of an injection well.

PRINCIPLES

The BHTV employs high-frequency acoustic energy to probe the inner surface of the casing in a well. A small-diameter piezoelectric transducer in the down-hole logging tool (Figure 59) transmits bursts of acoustic energy as it is rotated within the tool at three revolutions per second. The dominant frequency of the energy is about 1.3 megahertz (Wiley, 1980; Keys, 1980). The energy, which is transmitted at a rate of 1200 to 1600 pulses per second, is confined to a very narrow beam which is directed toward the casing wall. A portion of the energy is reflected by the wall back toward the transducer, which also serves as a receiver. The transducer converts the reflected acoustic energy pulses into electrical signals, which are utilized in producing the BHTV log. The combination of transducer rotation with the continuous vertical movement of the logging tool as it is pulled up the borehole results in a continuous log of the borehole being surveyed (Zemanek, et al., 1970).

The amount of energy reflected by the casing wall is a function of the physical properties of the wall surface. As Zemanek et al. (1969) observed, a smooth surface will reflect energy better than a rough surface, a hard surface better than a soft surface, and a surface perpendicular to the transducer (at the time it transmits/receives the acoustic energy) better than one that is at some other angle. In general, any irregularities on the casing wall surface will reduce the amplitude of the reflected signal.

The signals representing both the amplitude and the travel time of the reflected acoustic energy are transmitted to the surface via the logging cable; the amplitude signal is displayed on an oscilloscope. The BHTV obtains approximately 485 data points per transducer rotation, and 1.75×10^4 data points per foot of borehole surveyed at a logging speed of five feet per minute (Wiley, 1980). Each rotation of the transducer is dislayed as a horizontal sweep on the oscilloscope. The individual sweeps, which begin on the left hand side of the oscilloscope face, are triggered by a magnetic pickup (cased hole applications only--in an open hole, sweeps are triggered by a flux-gate magnetometer, which senses magnetic north and thus provides a means of determining log orientation). Each time a magnetic signal occurs, the electronic beam within the oscilloscope is returned quickly to the left side of the screen and sweeps across to the right side. Depth information is provided by a reading from the logging cable measuring sheave (Wiley, 1980). The result of the combination of all this information is an image of the casing wall that makes it appear as though the casing were split vertically and laid out flat. Because the entire 360° of the casing wall are scanned, the image produced on the oscilloscope is a true reproduction of the casing wall (Zemanek, et al., 1969). The actual BHTV log is made by taking a series of photographs of the image on the oscilloscope face.

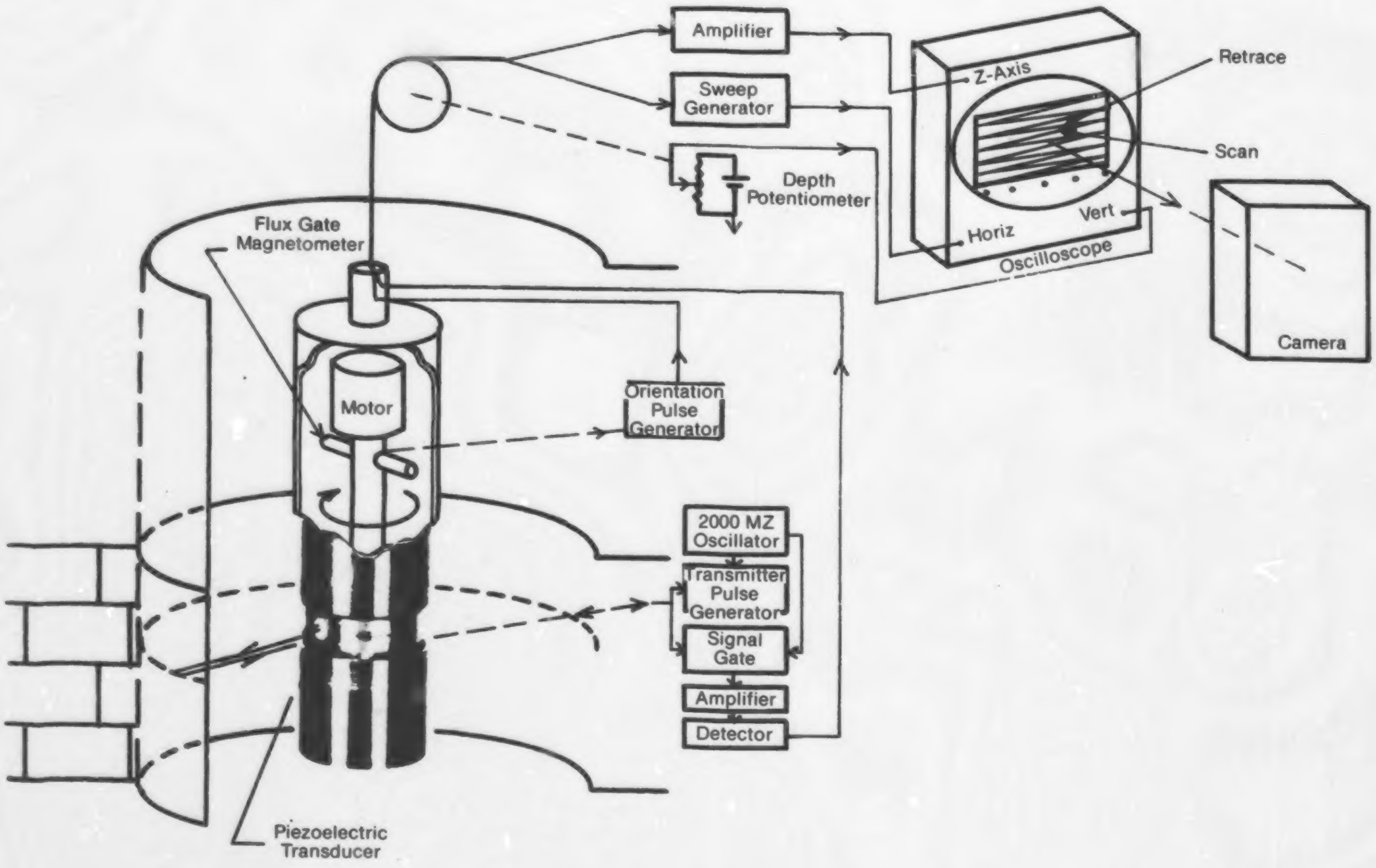

Figure 59. Block diagram of a borehole televiewer logging system (Zemanek et al., 1969).

In addition to displaying and recording signal amplitude, the BHTV records signal travel time. Travel time (time between transmitting and receiving pulses) is a function of casing diameter; uniform travel time throughout a section of casing indicates uniform casing diameter, while variations in travel time indicate aberrations in casing diameter. The preciseness with which travel time can be measured by the BHTV allows the creation of an extremely accurate acoustic caliper log, which compliments the acoustic image and is very helpful in interpreting the nature of casing anomalies (Schaller, et al., 1972).

EQUIPMENT

The original BHTV downhole tool, as described by Zemanek et al. (1969) is depicted in Figure 60. It consists of 1/2-inch diameter ceramic piezoelectric transducer, a flux-gate magnetometer, and a motor that rotates the transducer and magnetometer within the tool about the vertical axis. The magnetometer, which produces a pulse indicating the orientation of the tool each time it rotates past magnetic north, is not utilized in cased-hole applications because the casing severely attenuates the earth's magnetic field. A magnetic pickup replaces the magnetometer in cased-hole applications. (Wiley, 1980).

The tool described by Zemanek et al. (1969) is 3 3/8 inches in diameter and 11 feet long, and includes four bow-spring centralizers at the top and bottom to keep the tool centered in the casing. The tool is suited for use in wells as small as 5.5 inches in diameter. Continuous operation of this tool is possible at temperatures up to 300°F; maximum operating pressure is 15,000 psi. The temperature limit is imposed primarily by the electronic components of the downhole tool. A modified model of this tool, developed by the U.S. Geological Survey for use in geothermal wells, has been successfully operated at temperatures of 500°F (Keys, 1980).

Glenn et al. (1971) describe a slim version of the BHTV tool which is only 1 3/4 inches in diameter. This tool has been used through 2-inch tubing and even through standard 1 25/32-inch seating nipples to log open hole and casing below tubing as small as 3" in diameter. The slim BHTV is longer, at 15 feet in length, but is essentially the same tool as the larger model, and performance is similar, though resolution suffers somewhat as a result of miniaturization (Glenn et al., 1971).

Both tools described above operate on multiconductor (4 or 7 conductor) logging cable. The cable supplies power to the downhole tool and also conducts the signal generated by the tool to surface equipment, where it is processed and recorded. The surface equipment consists of an oscilloscope on which the image produced by the scanning action of the downhole tool is displayed, a camera or continuous chart recorder to record the image displayed on the

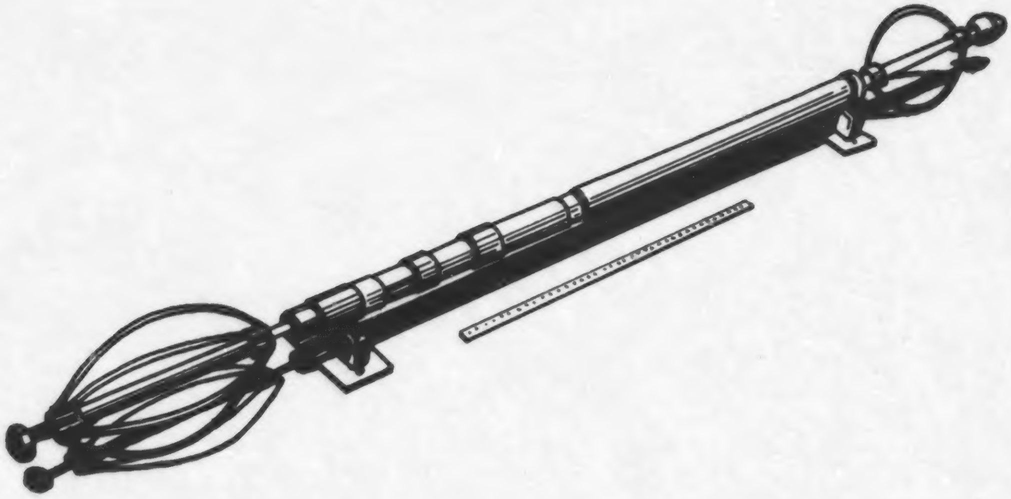

Figure 60. Assembled borehole televiewer logging tool (Zemanek et al., 1969).

oscilloscope and the necessary electronic circuitry to control the tool from the surface. The record may also be recorded on magnetic tape for later playback and image enhancement.

PROCEDURES

The BHTV log is made as the tool is pulled up the well; the result is a continuous record of well conditions. Because the tool is moved vertically simultaneously with the rotation of the transducer within the tool, a continuous log of the casing wall is produced. Logging speed is normally from 5 to 6 feet per minute at the expanded scale necessary to resolve casing leaks.

For the BHTV to be run in an injection well, the well must first be taken out of service to accommodate the logging equipment. In an injection well utilizing a tubing and packer completion, the tubing must be removed to allow the BHTV to probe the casing wall. For the BHTV to operate efficiently, it is necessary to have some type of liquid present in the well. Because the BHTV is an acoustic device, it performs equally well in clear water, salt-saturated brine, crude oil, or drilling mud, though with the latter the quality of the log obtained is diminished somewhat (Zemanek et al., 1970).

When the BHTV is used to survey casing, the first pass is usually made at a reconnaissance gain setting. At this gain, casing collars and joints will be visible on the log. If any anomalies other than those due to casing collars and joints are observed, the casing is resurveyed at different gains to optimize the identification of the anomaly.

INTERPRETATION

As the various conditions of the inside of the casing are surveyed, they are imaged on the oscilloscope and on photographic film, which becomes the permanent log of the well. Whenever a smooth, hard surface normal to the transducer is scanned, the reflected signals will be of a uniform amplitude that, in turn, will produce uniform intensity traces on the oscilloscope; the image will thus consist of only bright traces. However, when an irregular portion of the casing, such as a casing collar or joint, a split, a perforation, or an area of deterioration or collapse is surveyed, the amplitude of the reflected signal decreases, causing the intensity of the oscilloscope traces to decrease. The result is a dark trace of low reflectivity on both the oscilloscope and on the photographic image. This visual comparison of casing wall image intensity at various points within the well is the only interpretation necessary with the BHTV.

A typical photographic image size is 2 1/2 inches (vertical scale of the log, which corresponds to well depth) by 2 inches (horizontal scale of the log, which corresponds to the azimuth of the casing wall). An interval of 10 feet or less is represented on the vertical scale, while the circumference of the casing is represented on the horizontal scale (W.S. Keys, personal communication, 1983).

Even though the quality of the photographic image is normally very good, the data presented are obviously quite compressed. Thus, in order to enhance the ability of the BHTV to resolve small features, improved methods of handling and displaying the data have been developed. Keys (1980) reports that the U.S. Geological Survey has developed a system for recording the BHTV signal on magnetic tape. Playback of the data recorded in this manner provides the opportunity to improve the quality of the BHTV log. Jageler (1980) describes a method for taping field data in analog form to allow reprocessing to enhance image quality. This technique allows replaying of the data at any gain or televiewer setting. Digitizing of the analog data to assist in further enhancment of image quality is also possible using this technique. Pasternack and Goodwill (1983) describe the methods for and applications of digital BHTV logging.

Resolution of the BHTV log is a function of the characteristics of the oscilloscope, the photographic film, the logging speed, the type of the fluid in the well, and the various electronic parameters. The characteristics of the oscilloscope and photographic film are fixed, for all practical purposes. Log resolution is greater with slower logging speed, and is better in water or other homogeneous fluids than in heavy drilling mud or in a liquid with entrained gas. In a 6" casing filled with water, features as small as 1/32-inch wide can be recognized (Zemamek et al., 1970) The adjustment of the various electronic parameters, especially the gain setting of the receiving amplifier, is perhaps the most critical factor in image resolution with the BHTV; this is done at the discretion of the operating engineer. In general, lower gain will emphasize the smaller irregularities in the casing being surveyed. Higher gain settings tend to "burn out" the smaller defects and thus put the emphasis on the larger anomalies (Schaller, et al., 1972). If adjustments are improperly done, the resolution may not be adequate to recognize small casing defects. The technique described by Jaegeler (1980) above eliminates operator control of instrument settings, and thus allows for optimal resolution.

COST

At the time of writing of this report, only one service contractor offered BHTV as a commercial logging service. Fees charged for the BHTV service, in 1982 dollars, are found in Table 17.

Additional costs which may be incurred as a result of contracting for a BHTV survey include the cost of renting a logging truck, operator travel expenses, parts equipment shipping, and living expenses. It is estimated that the cost for logging a 4000-foot injection well would be in the range of $4500 to $8000, though the great number of variables involved could cause a wide variation in the range of costs for this service (J. West, personal communication, 1983). This cost is competitive with other logging services.

TABLE 17. TYPICAL CHARGES ASSOCIATED WITH BOREHOLE TELEVIEWER SURVEYS

- In-transit time
  - First operator at $50.00/hr.
  - Second operator at $30.00/hr.

- Stand by time
  - First operator at $55.00/hr.
  - Second operator at $30.00/hr.

- Logging, Maintenance or Service time
  - First operator at $62.00/hr.
  - Second operator at $37.50/hr.

ADVANTAGES AND DISADVANTAGES

The BHTV offers several distinct advantages over other cased-hole logging methods used in the location of casing defects. The primary advantage is that the BHTV provides a true representation of the casing in the form of an image that can be easily recognized as that of the casing's inner wall. Little if any true log interpretation must be performed because the BHTV log is a straightforward visual log of downhole conditions. However, experience with this type of log is necessary for correct interpretation. The log can be a simple photographic record or a videotape record which can be replayed at any time. While the borehole television (Section 13) offers much the same service (providing a visual image rather than an acoustic image), the BHTV offers advantages over these optical devices. It is able to operate in less favorable environments (higher temperatures and pressures; wells filled with nearly any homogeneous liquid) and it is available in smaller diameter tool sizes to fit down smaller wells. In addition, the casing wall does not have to be clean for a BHTV survey to be run. Other advantages include the potential availability of new techniques that allow for analog taping of BHTV data and subsequent digitization, leading to enhancement of the BHTV data and improved imaging.

As with other logging techniques, the BHTV survey requires that the well be taken out of service and the injection tubing pulled in order for the survey to be performed. This may result in significant down time for the well.

While the BHTV survey is competitive on a cost basis with other cased hole logging techniques, it is at present only offered through one specialized service company. This greatly limits the availability of the service to injection well operators. A related problem is that while the BHTV survey has been utilized extensively in open hole applications (particularly research-oriented work involving evaluation of fractures), it has seen limited application in cased holes.

EXAMPLES

Figure 61, from Zemanek et al., (1969) illustrates the use of BHTV for locating and determining the exact size of a hole in casing that has burst. The first log, on the right, was run at a reconnaissance gain setting such that even small irregularities were located. The second log from the right was a log rerun at a higher gain to locate major defects. The third log from the right was a re-run to preserve a one-to-one relationship between the vertical and horizontal scales. Thus, the exact shape of the defect is as depicted on this log. This is confirmed by a photograph of the casing shown on the extreme left.

Figure 62, also from Zemanek et al., (1969) is a BHTV log run in a perforated section of casing. The vertical scale of the log on the left is compressed with respect to the horizontal scale (casing circumference). This is the normal depth scale for logging, however at this scale the perforations appear distorted. The depth scale on the log on the right has a one-to-one relationship with the horizontal scale. The perforations take on their normal circular appearance.

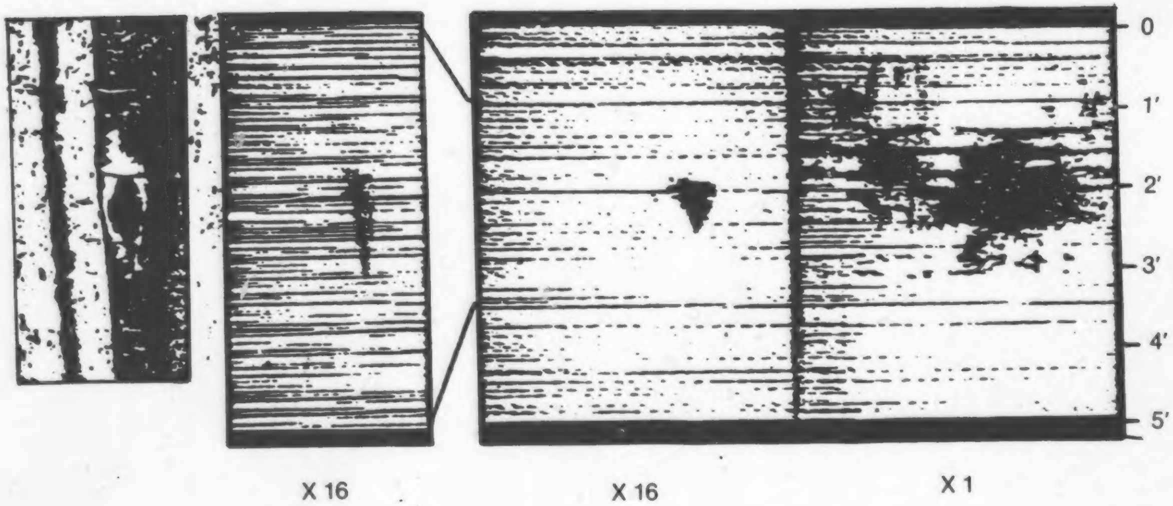

Figure 61. Borehole televiewer casing inspection logs of a casing blowout (Zemanek et al., 1969).

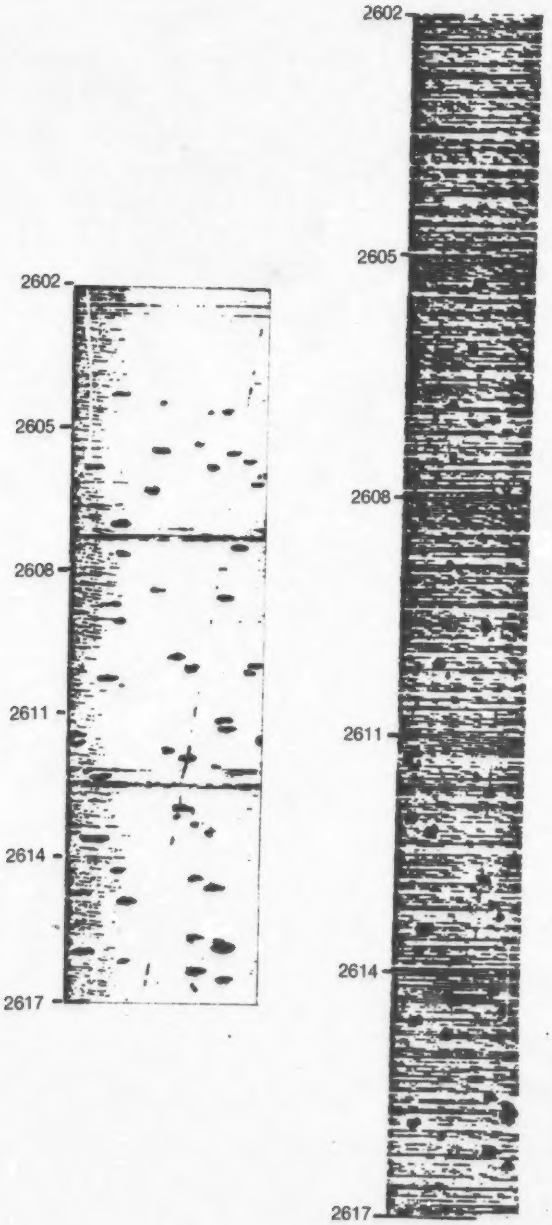

Figure 62. Borehole televiewer casing inspection logs of perforations (Zemanek et al., 1969).

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SECTION 15

FLOWMETER SURVEYS

SYNOPSIS

A flowmeter survey is made by using a downhole tool which measures the rate of flow of borehole fluids. In injection wells, flowmeters may be used to help determine the location of leaks in the casing, tubing, packer or plug. The survey is conducted during injection of fluids by using small diameter tools which can be used in tubing as small as two inches. Three different types of flowmeters -- packer, continuous and fullbore -- are available for differing flow rates and fluid conditions.

PRINCIPLES

A flowmeter is a downhole logging device which is used to measure the rate of flow of borehole fluids (Ransom, 1975). A flowmeter survey measures the rate of fluid flow at any desired point in the well and helps determine the direction (up or down) of fluid movement. In injection wells, flowmeter surveys may be used to help locate leaks in the casing, tubing, plugs or packers. Flowmeter surveys only indicate the amount of fluid which is leaving the borehole at specified intervals and cannot be used to determine fluid flow behind the casing or within the formation (Warner and Lehr, 1977).

Flowmeter surveys may be run in the tubing, casing or in an open hole with a variety of different types of flowmeter tools. Regardless of the differences in tool types, flowmeters or spinners operate on basically the same principle. The downhole part of the tool contains an impeller inside a protective housing which is rotated by the motion of borehole fluid past the blades (Ransom, 1975) (Figure 63). As the spinner rotates, electrical pulses are sent up the cable to be recorded at the surface. The number of pulses is directly proportional to the average velocity of fluid passing through the tool (Syms et al., 1982). With the proper hole size information, the velocity can be converted to barrels per day or recorded as a percentage of the total flow (Bird and Bullard, 1961).

When injection rates are held constant, the velocity of the fluid is proportional to the diameter of the casing, tubing or borehole. When the cross sectional area either is known (such as for casing or tubing) or can be determined with a caliper log (for open boreholes), points and rate of fluid exit can be determined.

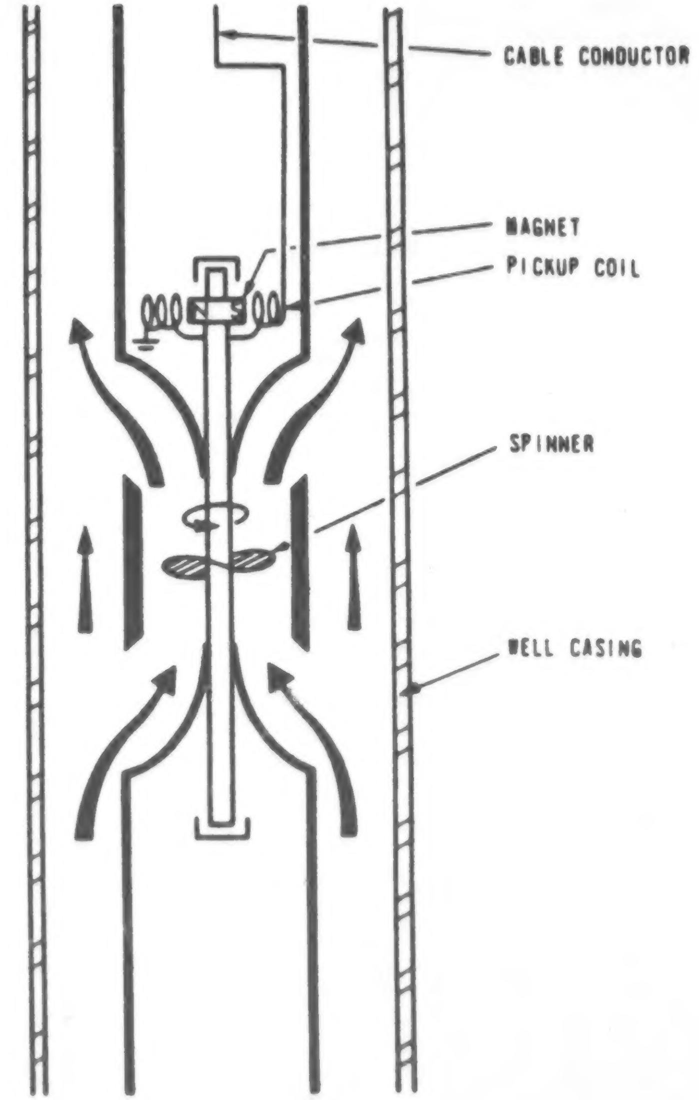


Figure 63. Diagram showing parts of a flowmeter (Schlumberger Services Catalog, 1978).

EQUIPMENT

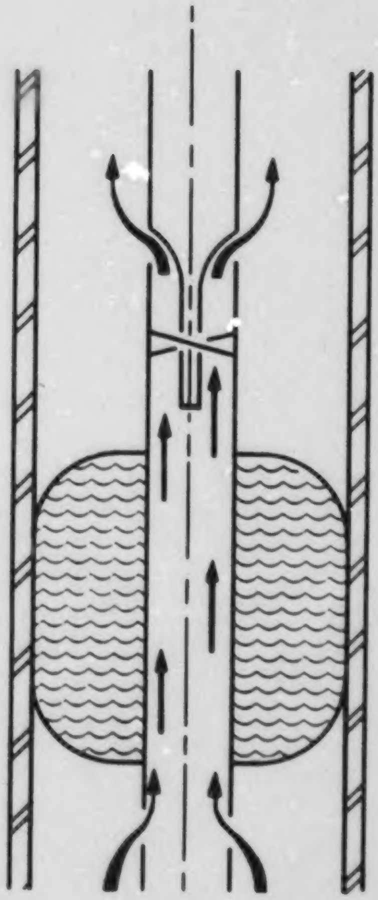
There are three basic types of flowmeters: packer, continuous and fullbore. For best results, all flowmeters should be centered in the well by bowsprings or similar devices. A packer flowmeter is a flowmeter which uses an inflatable packer to restrict flow around the tool and channel all fluid flow in the well by the impeller in the flowmeter (Figure 64). Because they channelize the flow, packer flowmeters are suitable for low flow rates. Packer flowmeters are available in a range of sizes which will fit into tubing as small as 2 inches in diameter, with packers that will seal a hole as large as 9 5/8 inches in diameter. Because of problems with maintaining the packer seal, this device is not as commonly used as other types.

Continuous flowmeters are the most commonly used flowmeter device. Figure 65 shows two different spinner configurations common in continuous flowmeters. Continuous flowmeters range in diameter from 1 5/8 inches to 5 inches and are typically rated to withstand pressures up to 15,000 psi temperatures to 350°F. Continuous flowmeters are generally better suited for higher flow rates than packer flowmeters. The measurable flow rate depends in part on the diameter of the tool and the size of the well. For example, some continuous flowmeters are designed to detect flows as small as 30 barrels per day (bpd) in a 7-inch well, while others function more reliably with minimum flow rates of 300-400 bpd in 4 1/2 inch wells. Results from continuous flowmeters may also be influenced by the presence of gas or liquids other than water (such as oil) in the well. Continuous flowmeters are best suited to applications where flow is entirely in the liquid phase.

Fullbore flowmeters are the most sophisticated flowmeter devices. The tool can be collapsed to 1 11/16 inches in diameter and is suitable for well diameters from 3 1/2 to 9 5/8 inches inside diameter. They are designed to overcome some of the limitations of continuous flowmeters. Fullbore flowmeters collapse to a diameter of 1 11/16 inches for entry into small diameter tubing, but expand once they are positioned in the hole (Figure 66). This expansion capability increases the accuracy of the log by enabling the blades of tool to occupy a significant portion of the well diameter. Fullbore flowmeters can be effectively used in holes ranging from 3 1/2 to 9 5/8 inches inside diameter and in a wide range of flow rates and multiphase flow. Use for flow rates as low as 50 bpd in 3 1/2 inch pipe and 200 bpd in 5 1/2 inch pipe are common.

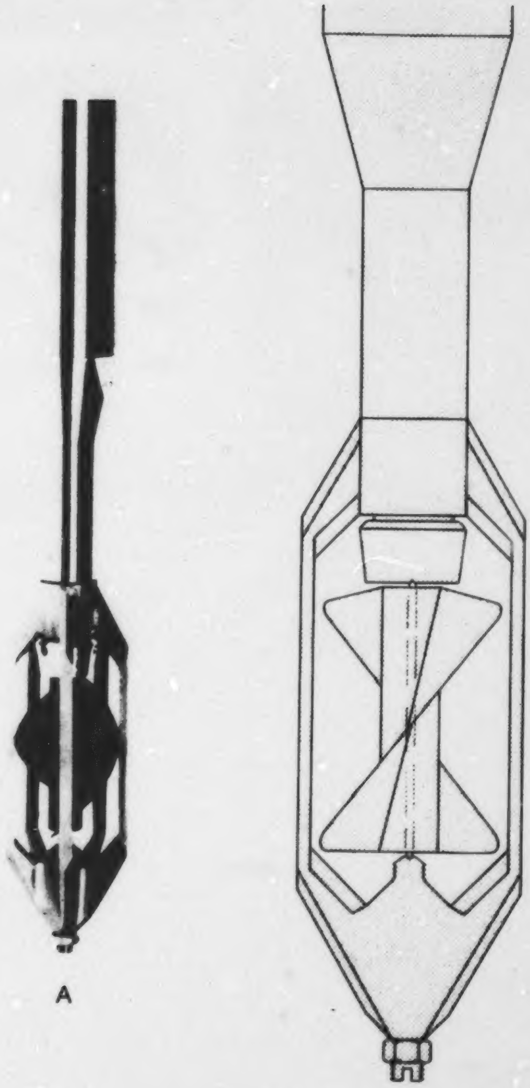
PROCEDURES

A flowmeter survey can be run in either the tubing or the casing of an injection well. A survey is run by lowering the tool into the well and beginning injection operations at a controlled rate. The tool is usually calibrated by measuring the flow at a point above a suspected leak or the known injection zone. A packer flowmeter survey



Packer Flowmeter

Figure 64. Diagram showing packer flowmeter in a well (Ransom, 1975).



A

B

Figure 65. Two different spinner configurations in continuous flowmeters (A—Gearhart Industries, Inc. product literature, B—Cmelik, 1979).

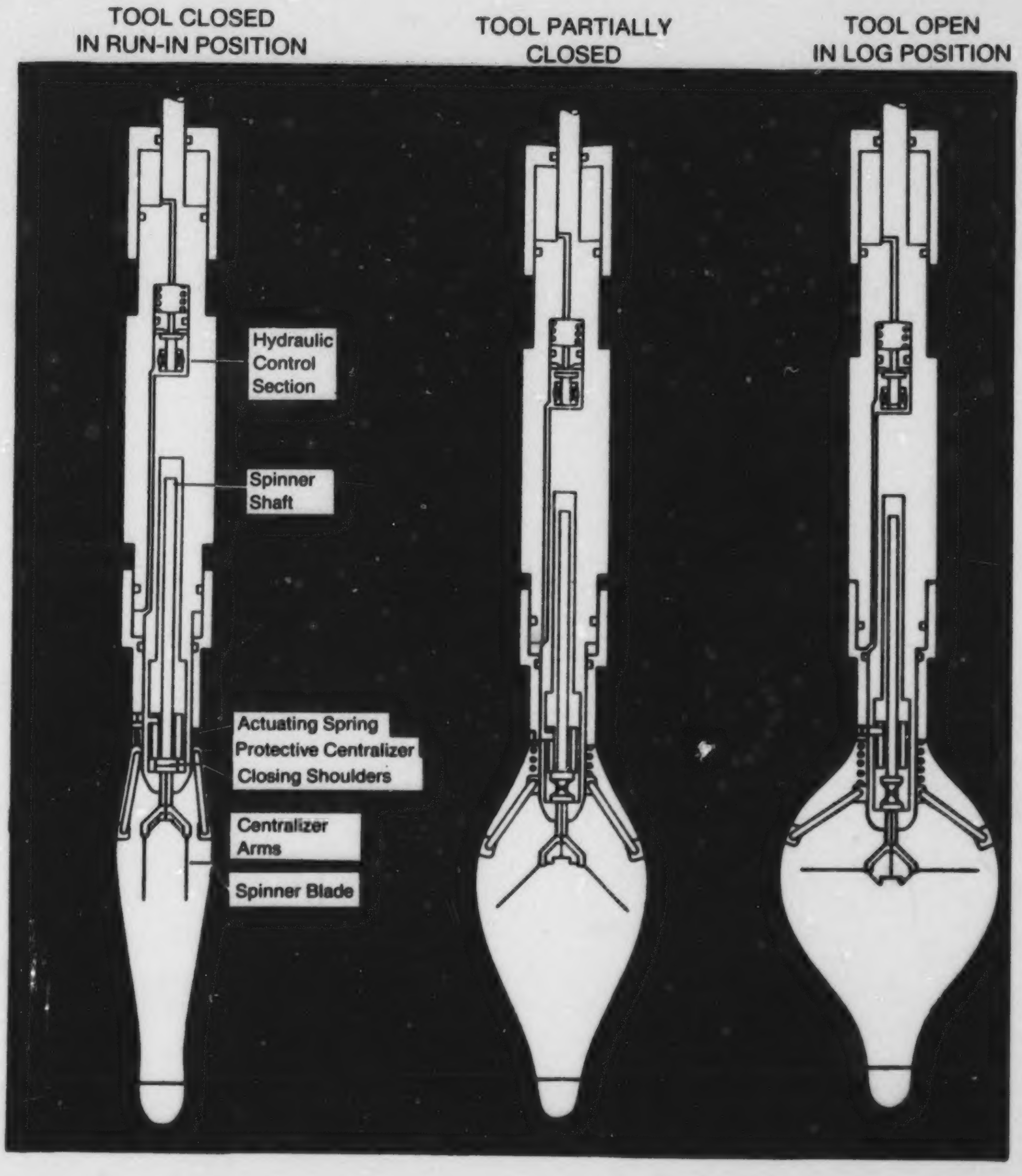


Figure 66. Fullbore flowmeter (Schlumberger Well Services product literature).

is run by positioning the tool at the depth of interest. A packer is inflated to fill the annulus between the tool and the casing or tubing. The fluid is thus forced to flow through a constricted region which contains the spinner. The profile is determined by taking readings at fixed points within the well. Figure 67 shows an electric log, well diagram, flowmeter log and injection profile for an injection well with an open hole completion. The flowmeter log details the depths at which readings were taken and displays the flow in barrels per day as a function of depth. The injectivity profile is another display of information obtained from a flowmeter which shows the receptivity of the formation (in barrels per day per foot) (bpd/ft) to injected fluids. In this example, the electric log and injectivity profile correlate to show the expected flow into the formation.

A continuous flowmeter survey is run by moving the tool at a constant rate past the zone of interest to obtain a continuous profile. The tool can also be held stationary to record measurements at specified intervals. The well is often logged both up and down the well to obtain more accurate information by log correlation. Figure 68 shows a log obtained using a continuous flowmeter to obtain readings with the tool held stationary and with the tool operating both up and down the well. The log is displayed in revolutions of the spinner per second. Fullbore flowmeters are run using the same procedures except that the spinner must be expanded during the logging operation.

INTERPRETATION

Interpretation of flowmeter surveys must be performed based on the type of flowmeter used and the tool-specific interpretation. In general, however, interpretation of a survey is accomplished by applying the basic principles illustrated in Figure 69. Figure 69 shows an idealized flowmeter survey with two points of fluid exit from the well (P_1 and P_2). The fluid is exiting at mass flow rates M_1 and M_2. Above P_1, the indicated flow would be proportional to $M_1 + M_2$ (Schlumberger, no date). Thus, by knowing the volume of fluid which should be leaving the well at a specified interval, differences in measured flow from expected flow rates can be used to help find leaks in the tubing or casing.

Errors in interpretation can be caused by fluctuating injection rates, fluctuation of cable speed in continuous surveys and channeling of flow around packer flowmeters (Morris and Cocanower, 1966). These sources of error may be minimized by monitoring equipment and operator performance prior to and throughout the entire logging procedure and by performing the logging operation both up and down the well. It should be noted that although logging speed must be held constant during a flowmeter pass, the speed may be changed between passes. The resulting log simply shows a displacement (Figure 70).

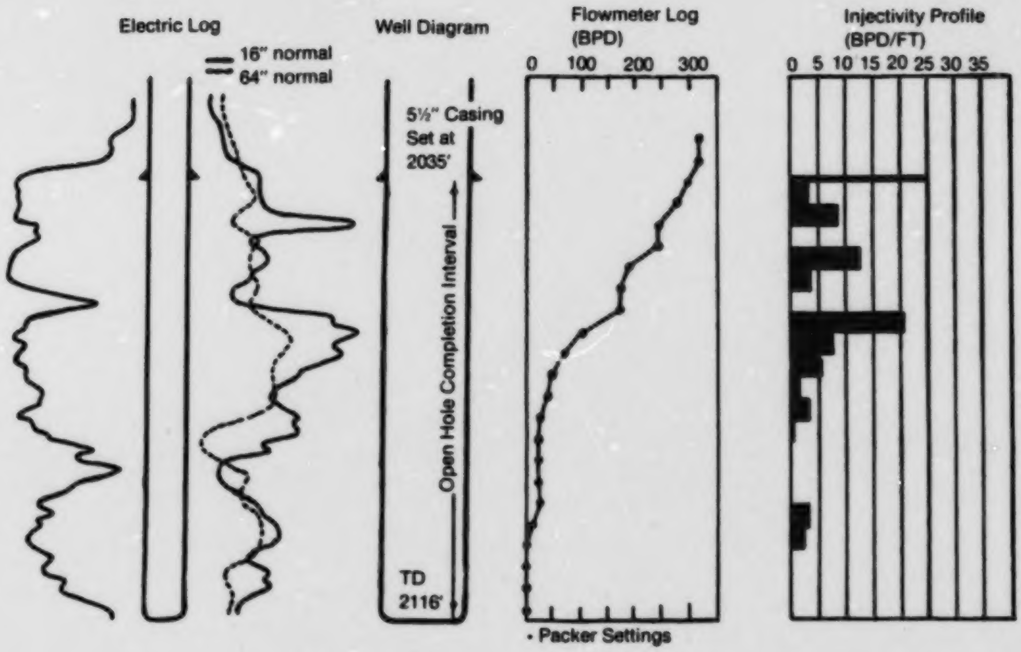


Figure 67. Packer flowmeter log in an injection well with an open hole completion (Bird and Bullard, 1961).

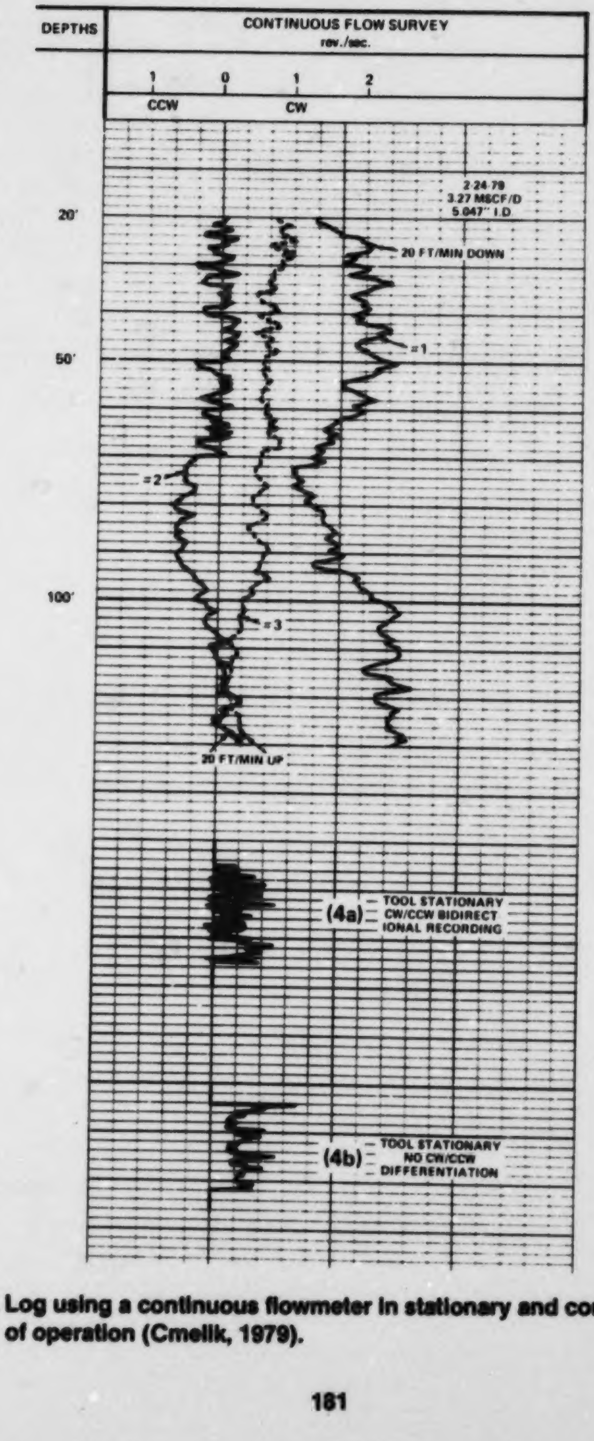


Figure 68. Log using a continuous flowmeter in stationary and continuous mode of operation (Cmelik, 1979).

CONTINUOUS FLOWMETER

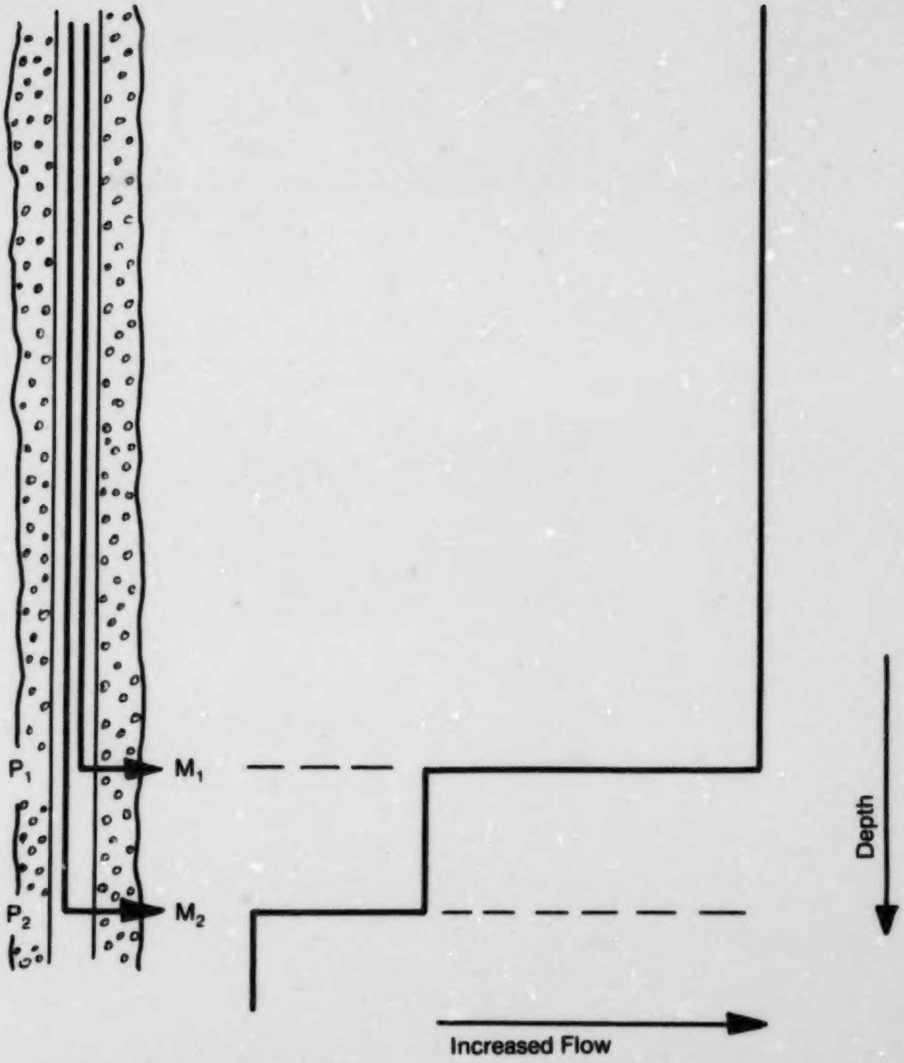


Figure 69. Diagram showing principles of interpretation for flowmeters (Schlumberger, no date).

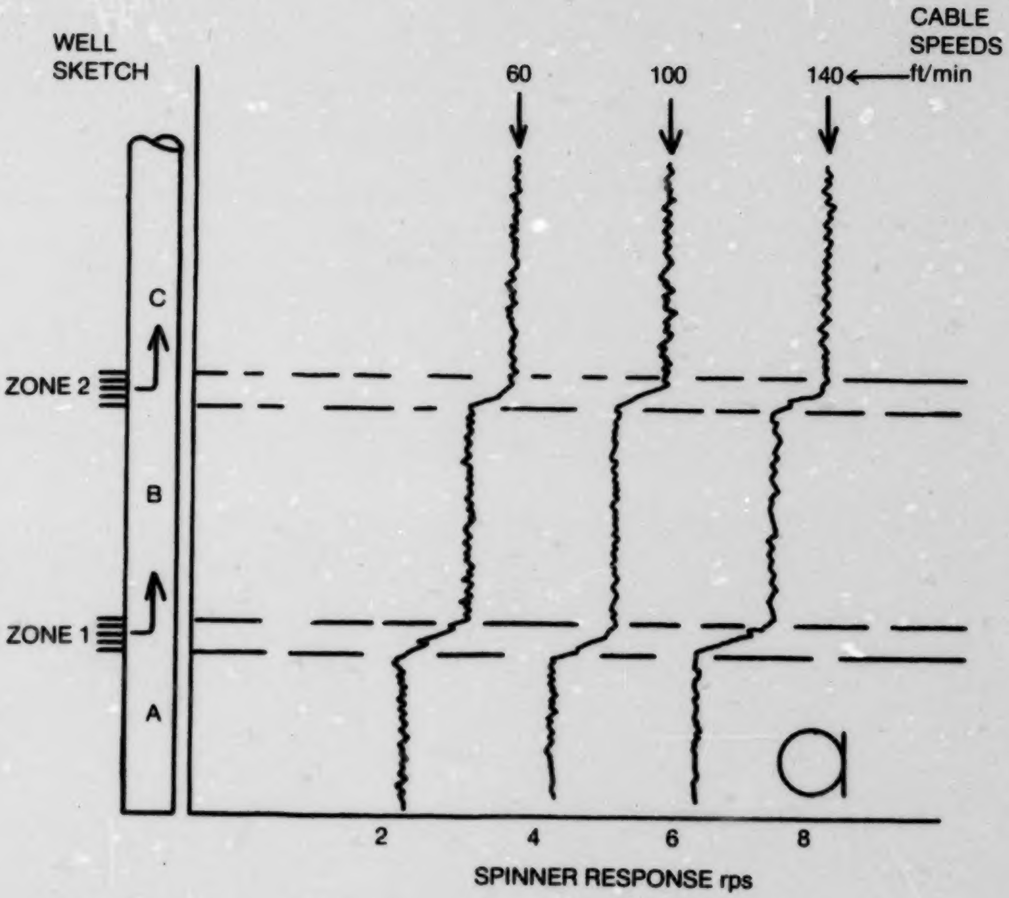


Figure 70. The effect of logging speed on flowmeter data (Dewan, 1982).

Interpretation of flowmeter data is often enhanced by combining the results with the results of other logs. This may be accomplished by using a combination tool which houses more than one sensing device or by actually performing additional individual logs. An example of a heat pulse flowmeter detection system is shown in Figure 71. This device is much more sensitive to low velocity flow than impellers, but cannot be used at high temperatures.

Knowledge of the completion practices in the well and of the type and characteristics of the injection formations may facilitate data interpretation. This may be particularly helpful in older wells where no data on initial flow conditions were ever recorded (Godbey, 1962).

COST

The cost of conducting a flowmeter survey is dependant upon the many general pricing variables outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Table 18.

TABLE 18. TYPICAL DEPTH AND LOGGING CHARGES FOR FLOWMETER SURVEYS

	Low	High
Depth Charge		
per foot	$0.19	$0.33
minimum	$350.00	$990.00
Logging Charge		
per foot	$0.19	$0.33
minimum	$350.00	$950.00

Refer to Table 7 for a listing of companies surveyed which perform this service.

ADVANTAGES/DISADVANTAGES

Flowmeter surveys can provide a relatively accurate determination of the location of leaks in the casing, tubing, packer or plug. Care must be exercised to ensure that injection rates are constant throughout the logging process. The single largest limitation of the method is that flow rates must be high enough to permit the device to function adequately. This flow rate is dependant on the tool design and diameter of the borehole.

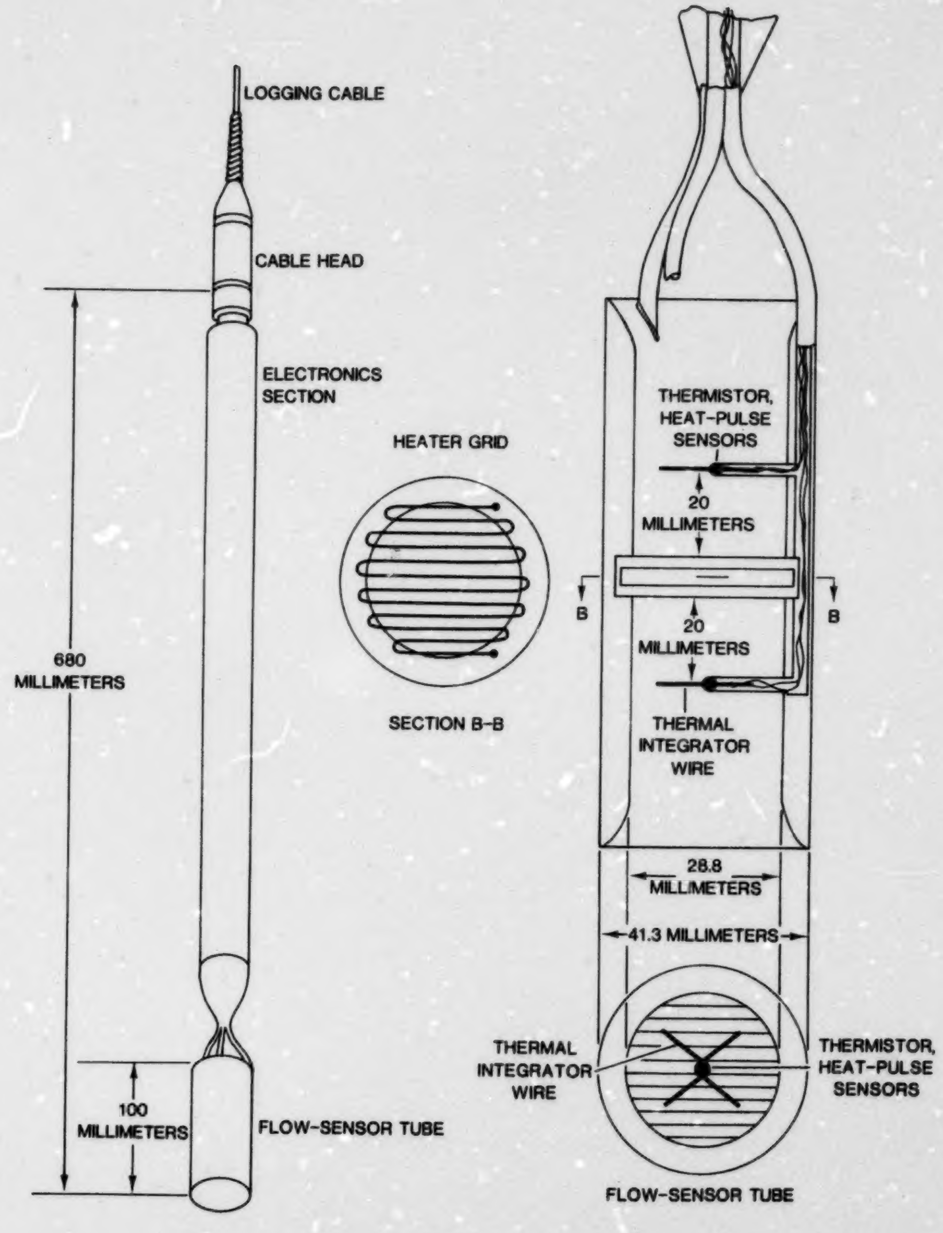


Figure 71. Heat pulse flowmeter detection system (Hess, 1982).

EXAMPLES

Figure 72 shows the results of a flowmeter survey displayed as an injectivity profile, compared with a core analysis and microlog of the well. A leak in the casing between the perforations was found using the flowmeter. The flow rate was too high to be accounted for by the leak alone, so fracturing in the upper section was also suspected (Godbey, 1962).

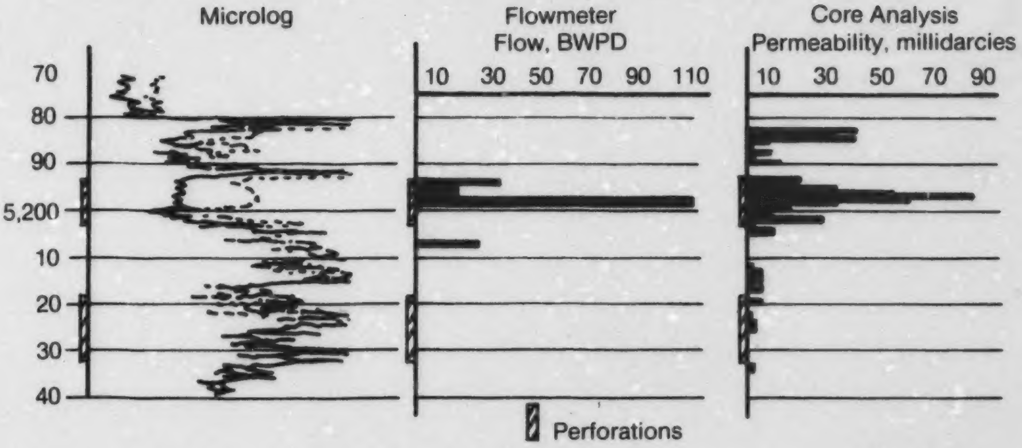


Figure 72. Results of a flowmeter survey showing a leak in the casing between perforations (Godbey, 1962).

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SECTION 16

RADIOACTIVE TRACER SURVEYS

SYNOPSIS

Radioactive tracer surveys or logs are used to study the movement of radioactive tracers in the immediate vicinity of the borehole (Ransom, 1975). They may be used in injection wells to help determine the presence of tubing, casing or packer leaks or to detect channeling behind the casing (Warner and Lehr, 1977). The radioactive tracer survey is conducted during injection operations by loading the radioactive tracer into the tool, lowering the downhole tool to a desired depth and ejecting a small amount of radioactive tracer. The tracer movement is detected by a gamma ray detector(s) which may be mounted in the tool in a variety of configurations. The tool may be held stationary or moved to follow the tracer movement. More than one run may be made; interpretation is accomplished by comparison of logs obtained both before and after radioactive tracer ejection.

PRINCIPLES

A radioactive tracer survey is conducted by ejecting a small quantity of short lived radioactive material, dissolved in an appropriate medium, into the fluids flowing in the tubing or casing. The transport and distribution of the radioactive tracer is monitored by gamma ray detectors (Lichtenberger, 1981). By comparing logs obtained during the survey to logs run before the tracer was injected, leaks in the casing, tubing or packer and channeling behind the casing can be detected.

Radioactive tracer surveys utilize the principle that unstable isotopes of elements emit radioactivity while decaying to reach a more stable state. In the process of decay, the isotopes emit alpha and beta particles and gamma rays. The alpha and beta particles are absorbed relatively quickly by the surrounding material and are therefore not measured in tracer surveys. The gamma rays, however, travel for a short distance through rock, cement and steel and can be detected by a sensor in the logging tool.

A variety of compounds can be used in radioactive tracer surveys. The primary concerns in selection of the proper radioisotope are the well conditions and the characteristics of the radioisotope. First, the radioisotope must be completely soluble in the injection fluid (Kelldorf, 1969). Second, the tracer should have an appropriate half life, long enough to be detected in the vicinity of the well, but not long enough to reach any area of ground water use. A half life is the length of time required for any given number of atoms to lose half their measurable radioactivity.

In Class II injection wells, the most common radioactive tracer is Iodine-131. Iodine-131 is typically available as water-dissolved radioiodine which has been stabilized to prevent oxidation in air, water or acid. The tracer is miscible in water and insoluble in oil. Iodine-131 has a half life of 8.1 days and is classified as a medium energy emitter (Johnson and Morris, 1964). Iridium-192 may also be used as a tracer in injection wells. However, because it has a 74 day half life, it is less commonly used.

The gamma rays emitted by the tracer are measured by a gamma ray detector. The two most common detectors in use are the scintillation crystal and the Geiger-Mueller tube (Lichtenberger, 1981). A scintillation detector usually contains a crystal of sodium iodide which is optically coupled with a light-sensitive amplifier tube or photomultiplier (Johnson and Morris, 1964). Gamma rays strike the crystal and produce small light flashes that are sensed and amplified by the photomultiplier (Dresser Atlas, 1976). This type of detector is 85 percent efficient in the detection of small amounts of radiation. However, the detector is not suitable for use at temperatures greater than 150°F unless some temperature protective housing is provided for the crystal (Kelldorf, 1969). Typically, this temperature restriction should not be a constraint in Class II injection wells (W.S. Keys, personal communication, 1983).

Where temperature is a concern, Geiger-Mueller tubes may be used. Their use has been largely discontinued except in small-diameter tools used in slim-hole completions where temperature protection is not possible (Dresser Atlas, 1976). Geiger-Mueller tubes can be used at temperatures up to 300°F, however efficiencies are limited to less than 10 percent (Kelldorf, 1969).

EQUIPMENT

The radioactive tracer logging tool basically consists of a tracer ejector and one or more gamma ray detectors. Figure 73 shows a tool with one detector; Figure 74 shows typical tracer tool configurations for tools with two detectors. The ejector may either employ a solenoid plunger, be well-pressure operated or operate by positive piston displacement (Johnson and Morris, 1964). All types of ejectors are activated at the surface.

The radioactive logging tool ranges in outside diameter from 1 1/2 inches to 3 3/8 inches depending on the design. The length of the tool varies by manufacturer and tool configuration, but ranges from 10 to 30 feet. Some tools can be used in downhole environments up to 300°F and at maximum pressures of 15,000 psi.

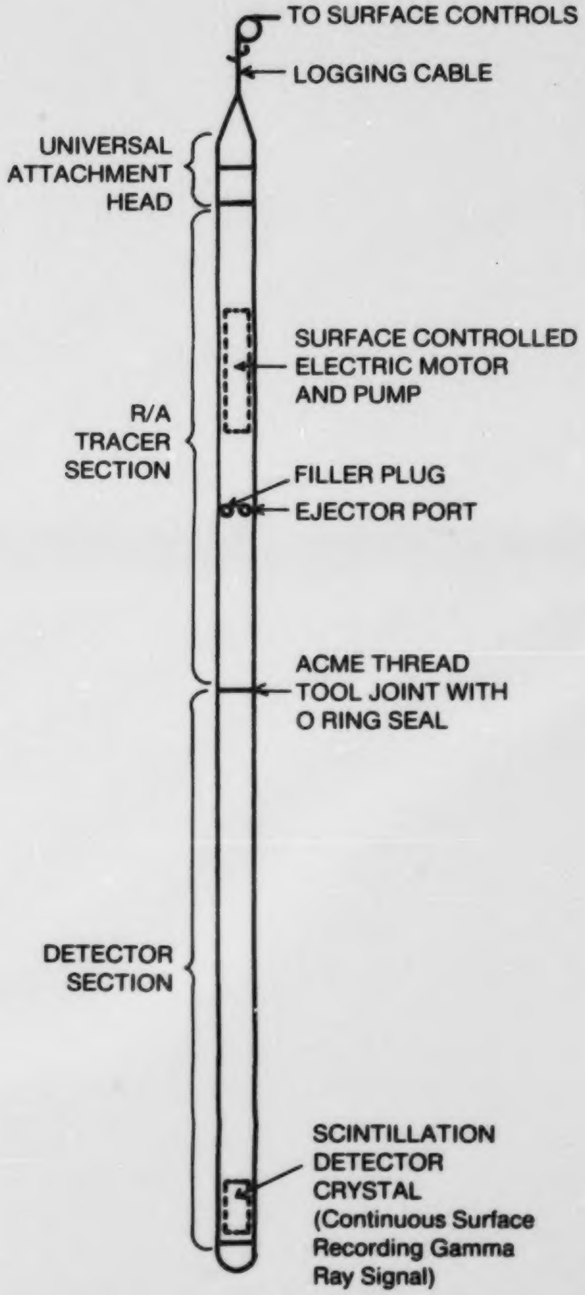
TO SURFACE CONTROLS
LOGGING CABLE
UNIVERSAL ATTACHMENT HEAD
SURFACE CONTROLLED ELECTRIC MOTOR AND PUMP
R/A TRACER SECTION
FILLER PLUG
EJECTOR PORT
ACME THREAD TOOL JOINT WITH O RING SEAL
DETECTOR SECTION
SCINTILLATION DETECTOR CRYSTAL (Continuous Surface Recording Gamma Ray Signal)

Figure 73. Radioactive tracer tool (Ford, 1962).

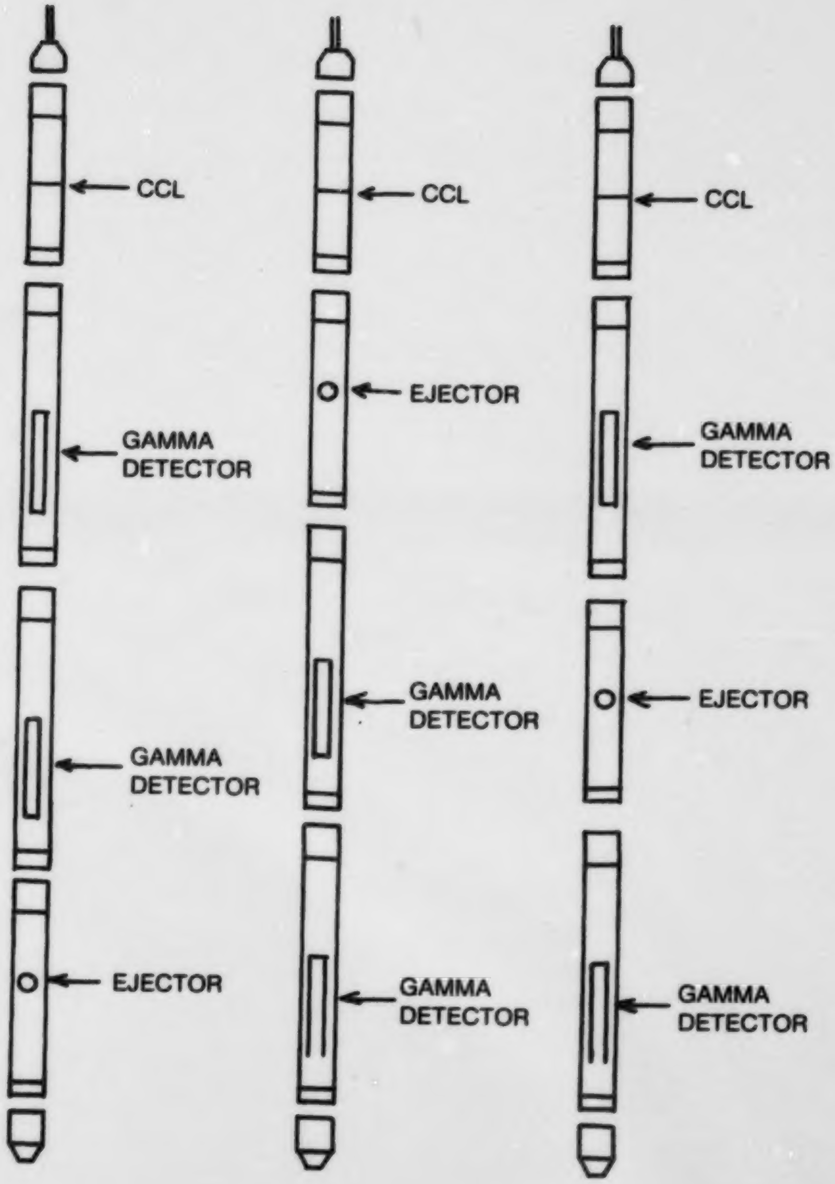

Figure 74. Three possible configurations of a radioactive tracer tool (Dewan, 1982).

PROCEDURES

Radioactive tracer surveys are performed on injection wells during injection operations. The survey is run by loading the ejector tool at the surface with the radioactive tracer through a filler plug. The tool is lowered into the well through an assembly which permits a minimum of alteration of the injection pressure. A natural gamma background log is run before ejection of the radioactive tracer to provide information on background conditions and correlation with previously run logs (Ford, 1962).

The tool is then positioned and a small amount of radioactive tracer is released. The tracer tool can either be held stationary or moved to trace the path of the radioactivity; the method of operation depends on the tool design and the purpose of the survey. In a two-detector tool, the tracer is injected into the well and the tool is typically held stationary. The time for the radioactivity to pass from one detector to another is recorded. If the slug moves too slowly, a leak may be indicated. In a single detector tool, the tool is typically moved to follow the radioactive tracer. By moving the tool, it may be possible to better locate channeling behind the casing or leaks in the tubing or casing. In either method, checks may be made at various depths to verify the presence or absence of leaks and/or channeling by changing the depth of ejection or direction of movement of the tool.

Because radioactive tracer surveys utilize radioactive materials, completion of a radioactive tracer survey must be performed by personnel which hold a current and valid Nuclear Regulatory Commission license or a state license. This ensures that proper procedures will be followed in the handling of the radioactive material. In addition, the Department of Transportation regulates the transport and handling of radioactive materials used in well logging operations. These licenses and regulations are not of general concern to the person requesting a log because the logging company is responsible for complying with the regulations and procedures.

INTERPRETATION

Interpretation of radioactive tracer surveys must be performed based on the type of tool used and the method of running the log. The following general situations and statements can be used to help interpret data obtained from a radioactive tracer survey. In general, a radioactive tracer log is evaluated by comparing the log(s) obtained after injection of the radioactive tracer with the log(s) obtained prior to radioactive tracer injection. The differences between these logs provide the basis for analysis. In addition, some basic statements about detection and flowrates may also be used to evaluate the logs. For example, if a tool configuration of an ejector between two detectors is used, a leaking packer in an injection well may be found by ejecting a radioactive tracer at the tubing shoe and observing the readings at each detector. Increased radioactivity at the higher detector will show movement of fluid in the tubing-casing annulus (Dewan, 1982). Using the same tool configuration, channeling of fluid behind the pipe at a casing leak can be found by ejecting the radioactive tracer above the leak. After moving the ejector below the leak, the radioactive tracer will not be present at the upper detector (Dewan, 1982).

A similar interpretation may be made by knowing the location of the injection zone and recording whether or not the radioactive tracer moves past this zone. This indicates either a leak or channeling (Edwards and Holter, 1956).

COST

The cost of conducting a radioactive tracer survey is dependent upon the many general pricing variables as outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Table 19.

TABLE 19. TYPICAL DEPTH AND LOGGING CHARGES FOR RADIOACTIVE TRACER SURVEYS

Depth Charge	Low	High
per foot	$0.27	$0.33
minimum	$540	$990
Logging Charge	Low	High
per foot	$0.28	$0.33
minimum	$550	$950

Refer to Table 7 for a listing of companies surveyed which perform this service.

ADVANTAGES/DISADVANTAGES

Radioactive tracer surveys provide an effective means for locating and evaluating leaks in casing, tubing and packer and channeling behind the casing. The primary advantage is that the survey is run during injection operations and can therefore provide a clear picture of what is taking place in the well under actual operating conditions. This also means that there is no need to interrupt the injection process to perform this service. The disadvantages to this method of checking mechanical integrity is in the choice of the correct radioactive isotope to ensure that no radioactivity reaches an area of ground-water use. Additionally, the correct strength of radioactivity must be made because the effective penetration of gamma rays is reduced by travel through a medium such as steel casing.

EXAMPLES

The following examples serve to illustrate the interpretation of logs to locate channeling behind the casing and a leak in the casing. Figure 75 shows the comparison of the logs run prior to and after the ejection of the radioactive tracer. The presence of radioactive tracer below the perforations indicates that fluid is being channeled behind the casing.

Figure 76 shows the technique used to locate a leak in the casing. Figure 76a shows the top detector of the tool located in the tubing and the bottom detector just below the tubing at the top of the perforations. When the radioactive tracer was ejected, radioactivity reached the top detector, but not the bottom detector. This suggests that no injected water was exiting through the perforations because the tracer would have to pass the bottom detector to reach the perforations. Figure 76b shows the survey being run with both detectors inside the tubing. The radioactive tracer passed both detectors, but still was not entering the perforations. Therefore, the water is interpreted as traveling up the hole inside the casing. Figure 76C shows movement of the fluid up the well when a radioactive tracer was injected at 2400 feet. In Figure 76D, the tracer was followed up the hole until 2020 feet where the movement became stationary. This indicated that the injected water exited through a leak in the casing at this point (Welex, 1968).

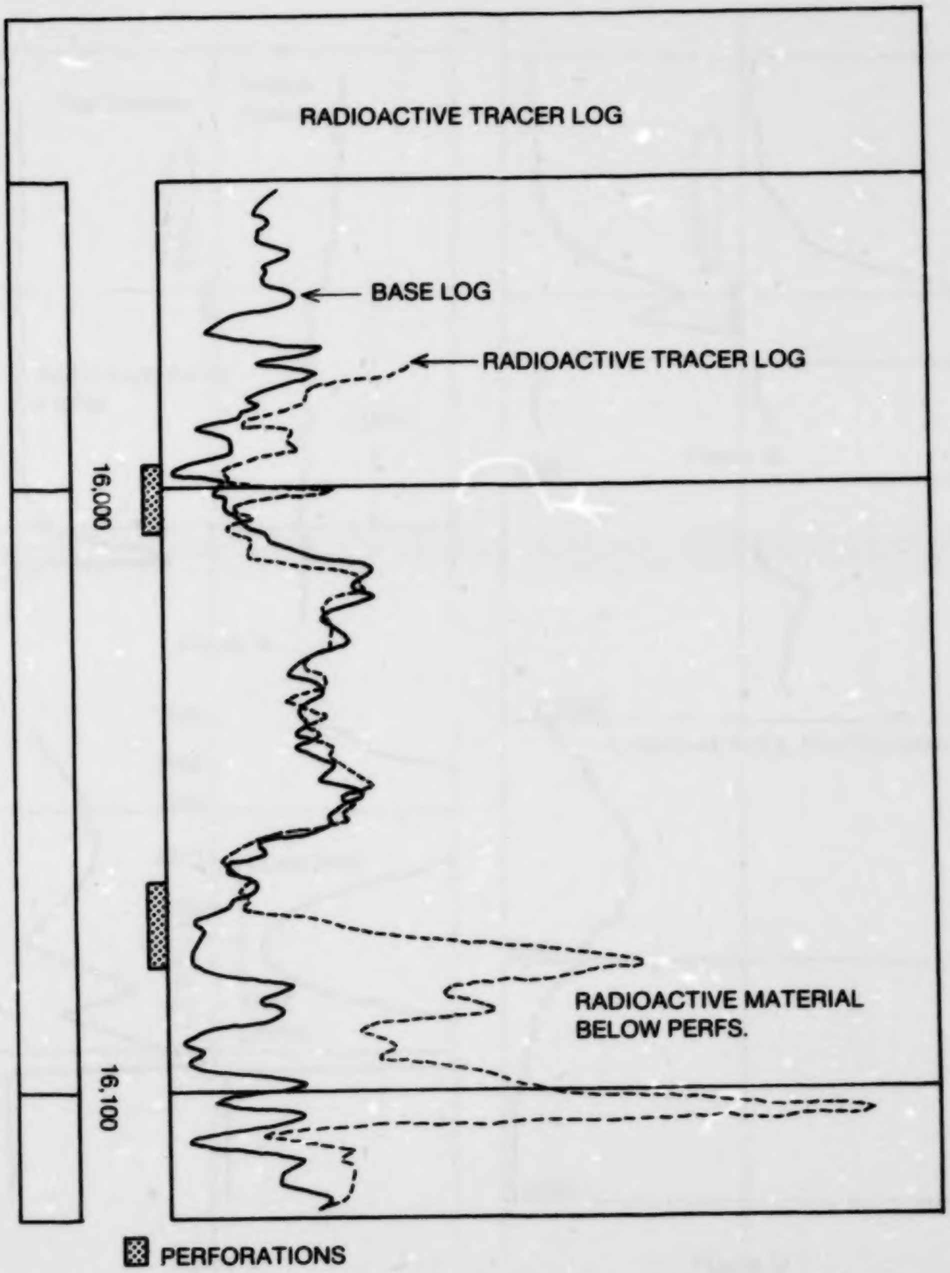

Figure 75. Radioactive tracer log showing movement of radioactive material below perforated zones (Dewan, 1982).

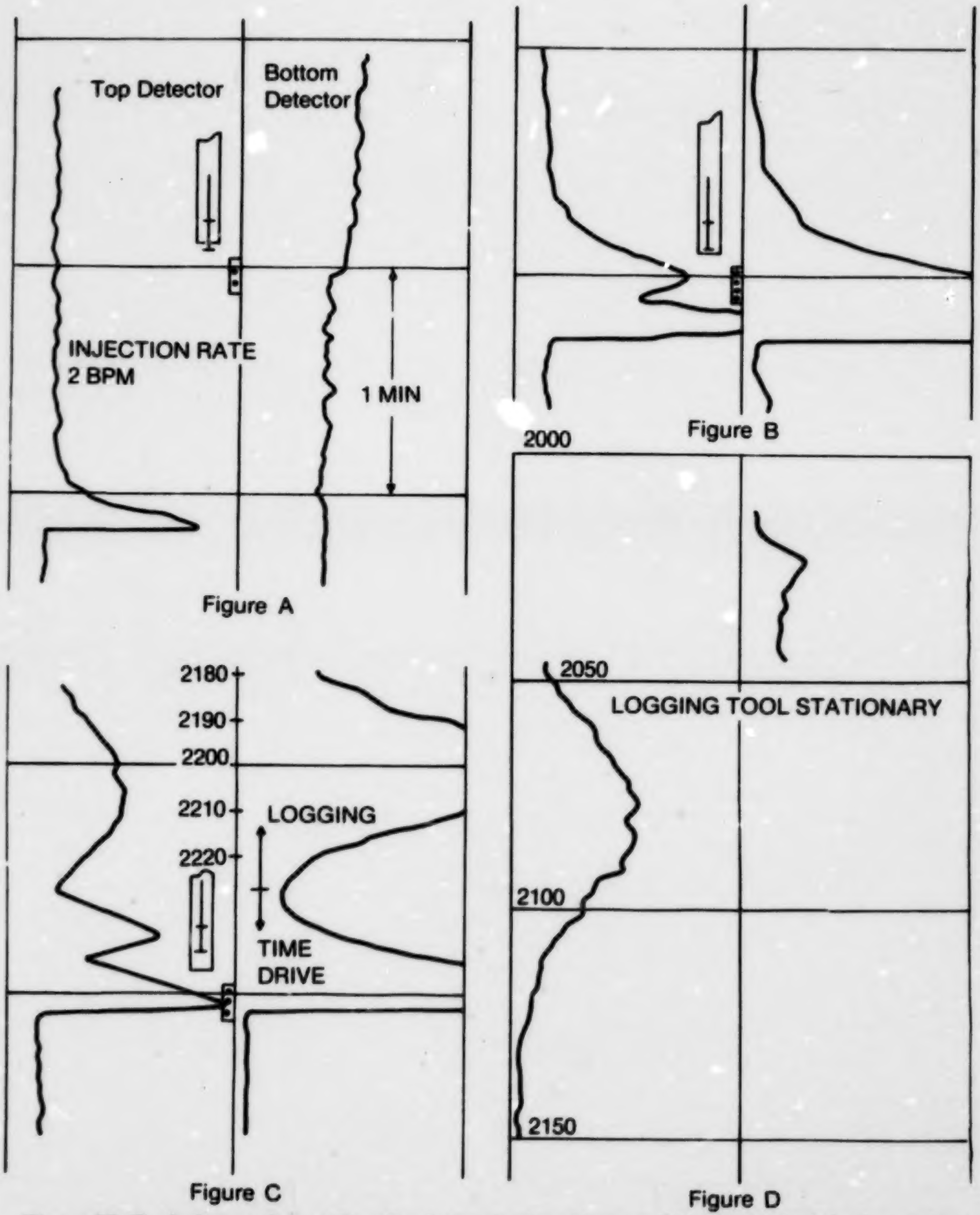

Figure 76. Technique using radioactive tracer tool and logs used to locate leak in the casing (Welex, 1968).

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SECTION 17

CEMENT BOND LOGGING

SYNOPSIS

The cement bond log is made using a downhole tool which emanates and records pulsed sound energy. In injection wells, cement bond logs can be used to determine the quality of the cement bond to the casing and to infer the presence of channels in the cement behind the casing. The log cannot be used to determine fluid movement in channels behind the casing. The cement bond log is run by centering the tool within the casing. This necessitates the removal of tubing from wells which are completed with tubing. The logging tool is suitable for use in casing as small as 2 inches in diameter and some tools can withstand maximum temperatures and pressures of 400°F and 20,000 psi. The cement bond log is a continuous log which can be recorded in a CBL (cement bond log) or combination CBL/VDL (variable density log) format. Interpretation of the cement bond log is enhanced when the combination is used. However, interpretation of logs made using different tools is difficult because there is no standardization within the industry. Even when proper interpretation techniques are employed, a great number of variables may influence the output and must be taken into consideration.

PRINCIPLES

Cement bond logs can be used to detect and locate areas behind the casing that have been inadequately cemented. Incomplete bonding of the cement to the casing or to the formation may provide avenues for the passage of fluids through the casing-borehole annulus. Although small channels and the presence or absence of fluid movement cannot be determined, cement bond logs can indicate that the potential for fluid movement exists.

A cement bond log utilizes a logging tool in a borehole which emits and records acoustic signals. The signal, produced by a transmitter within the tool, travels 1) through the fluid in the borehole to the casing, cement and formation, 2) along the casing and formation and 3) back through the fluid to the receiver (Figure 77). Because sounds travel at different velocities through different mediums, the sound waves from these different pathways will arrive at different times. The most common order of arrival is 1) the casing pathway, 2) the formation pathway and 3) the borehole fluid pathway (Gearhart, 1982). Figure 78 shows common pathways and illustrates typical travel times through each of the mediums.

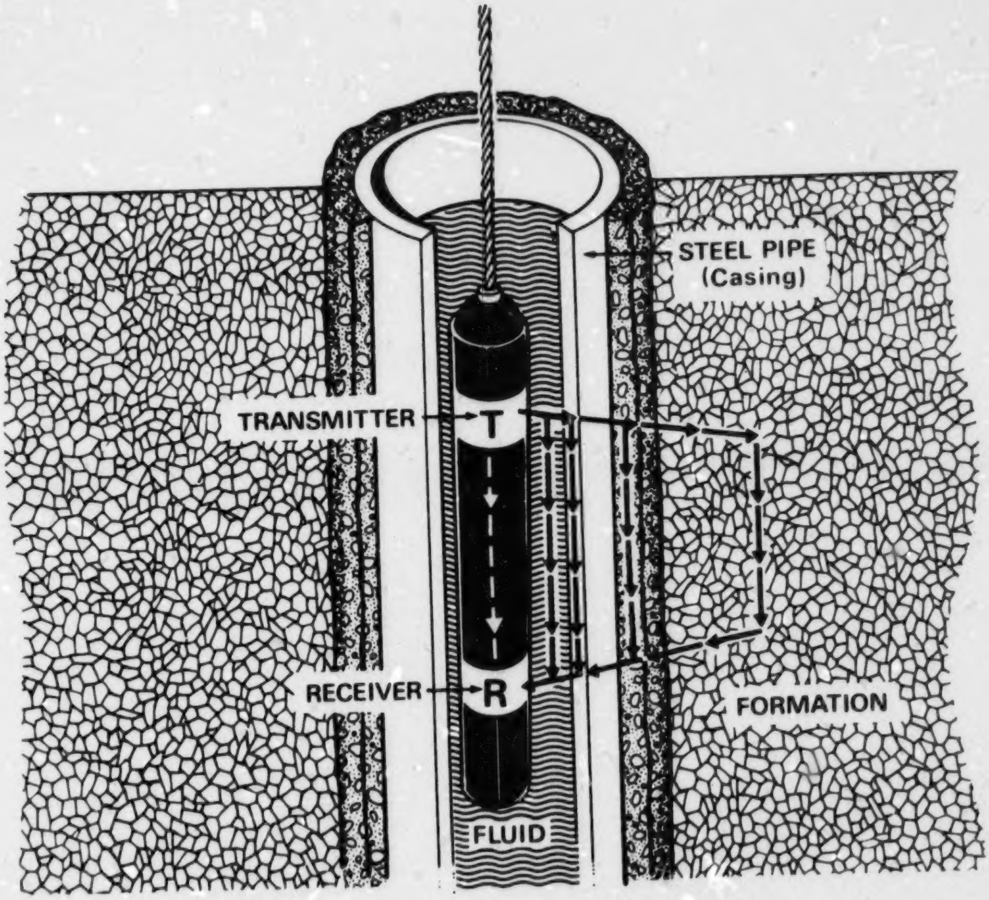

Figure 77. Basic cement bond log theory (Gearhart Industries, Inc., 1982).

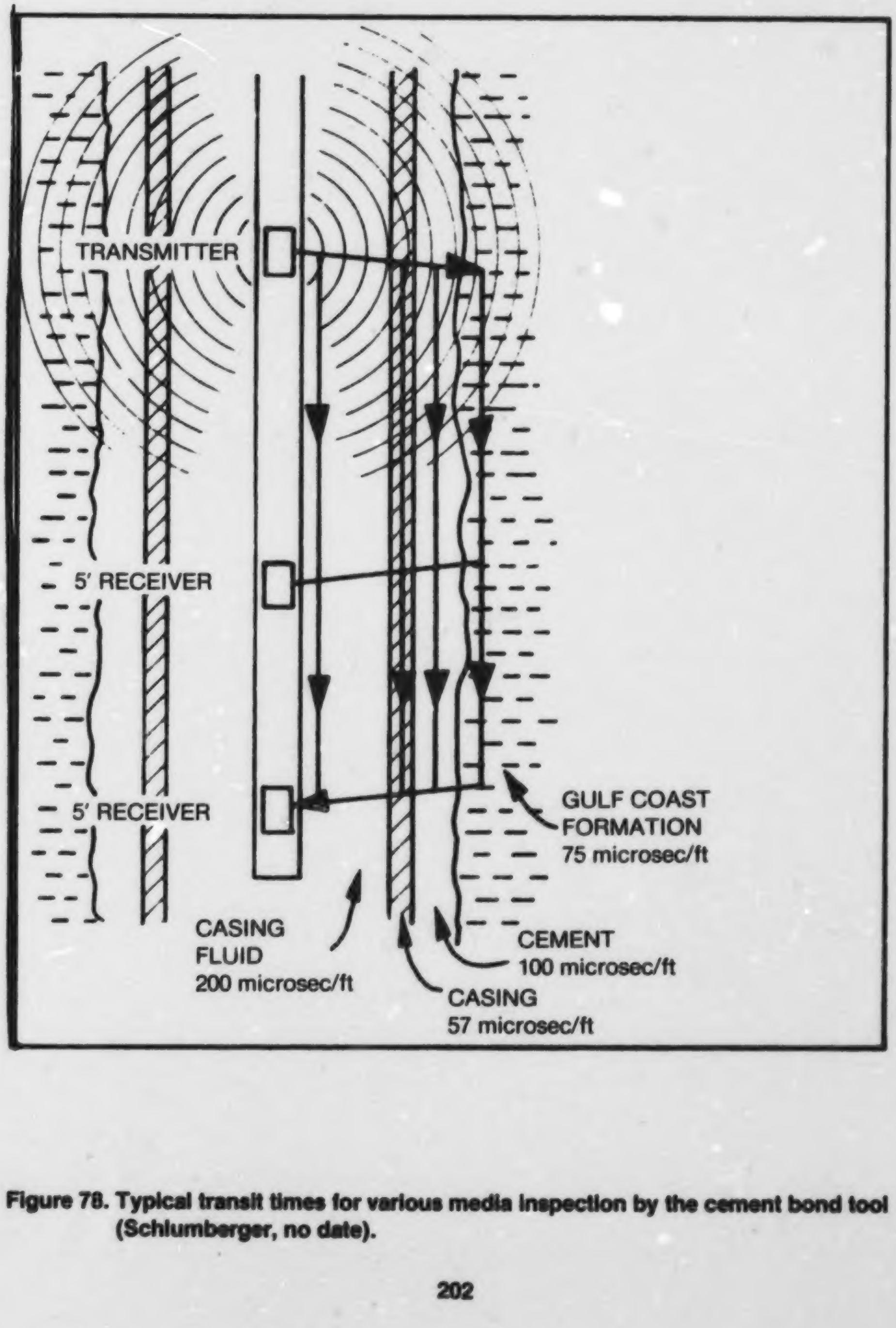

Figure 78. Typical transit times for various media inspection by the cement bond tool (Schlumberger, no date).

A cement bond log is made by recording the amplitude of the signal and the transit time necessary for that signal to reach the receiver through the casing pathway. According to Gearhart (1982), the amplitude of the signal recorded at the receiver is a function of:

1) the magnitude of the original sound pulse,

2) the internal diameter of the casing,

3) the type of fluid in the well,

4) the thickness of the casing wall,

5) the amount of cement bonded to the casing, and

6) the compressive strength of the cement bonded to the casing.

Figure 79 shows a typical cement bond log. The log is analyzed to evaluate the quality of the cement bond to the casing. In general, the amplitude of the signal received from casing which has no cement bonded to it is large. Conversely, when the cement and casing are bonded together, the signal is attenuated by the casing and therefore the signal at the receiver is very small (McGhee and Vacca, 1980). Often a second recorder will be used to measure all the energy in the wave train which arrives at the receiver. The primary purpose of this second recording method, called a variable density log (VDL), is to record the signal from the formation pathway (McGhee and Vacca, 1980). This output is then used to support the interpretation of the casing curve and to more clearly identify micro-separations in the cement (McGhee and Vacca, 1980).

The VDL is displayed as a series of alternating light and dark bands which represent the different pathways of the sound waves. Typically the casing arrivals will appear as regular bands and the formation arrivals as irregular bands (Figure 80). Because the two outputs (CBL and VDL) compliment each other, the two outputs usually appear as one log rather than as separate logs.

Although the cement bond log is simple in theory, the validity of the cement bond log and its interpretation is a source of controversy (Fertl et al., 1974). The American Petroleum Institute has recognized this problem and has formed a committee to offer suggestions on standardization of equipment and interpretation.

EQUIPMENT

The typical cement bond logging tool consists of a sonic transmitter and either one or two receivers located at specified distances from the transmitter (Figure 81). The transmitter-receiver spacings range from 3 to 7 feet, but 3 and 5 foot spacings are common (McGhee and Vacca, 1980). The shorter spacing is desired in the traditional cement bond log format (CBL) because it more clearly shows

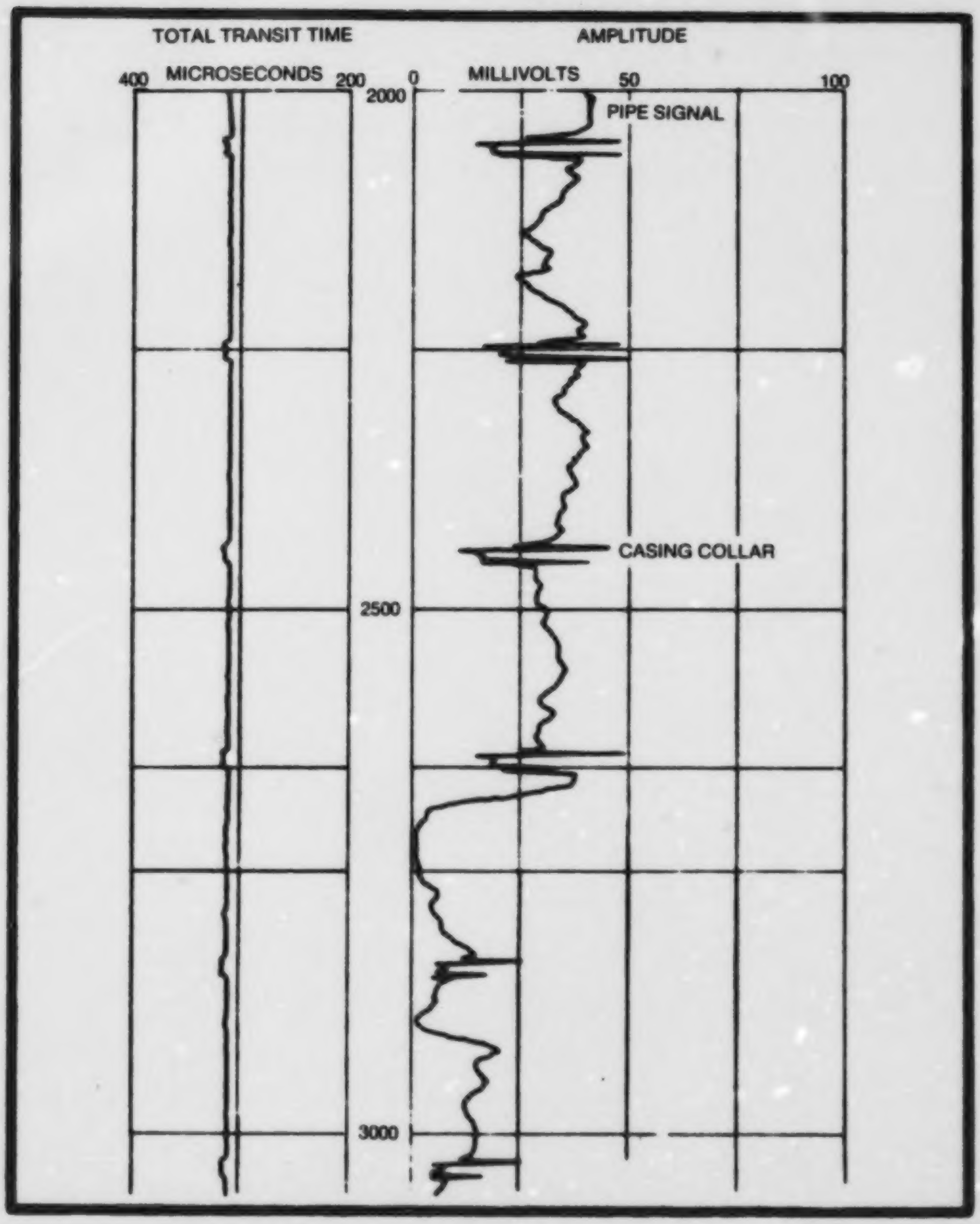

Figure 79. Typical cement bond log (Schlumberger, 1976).

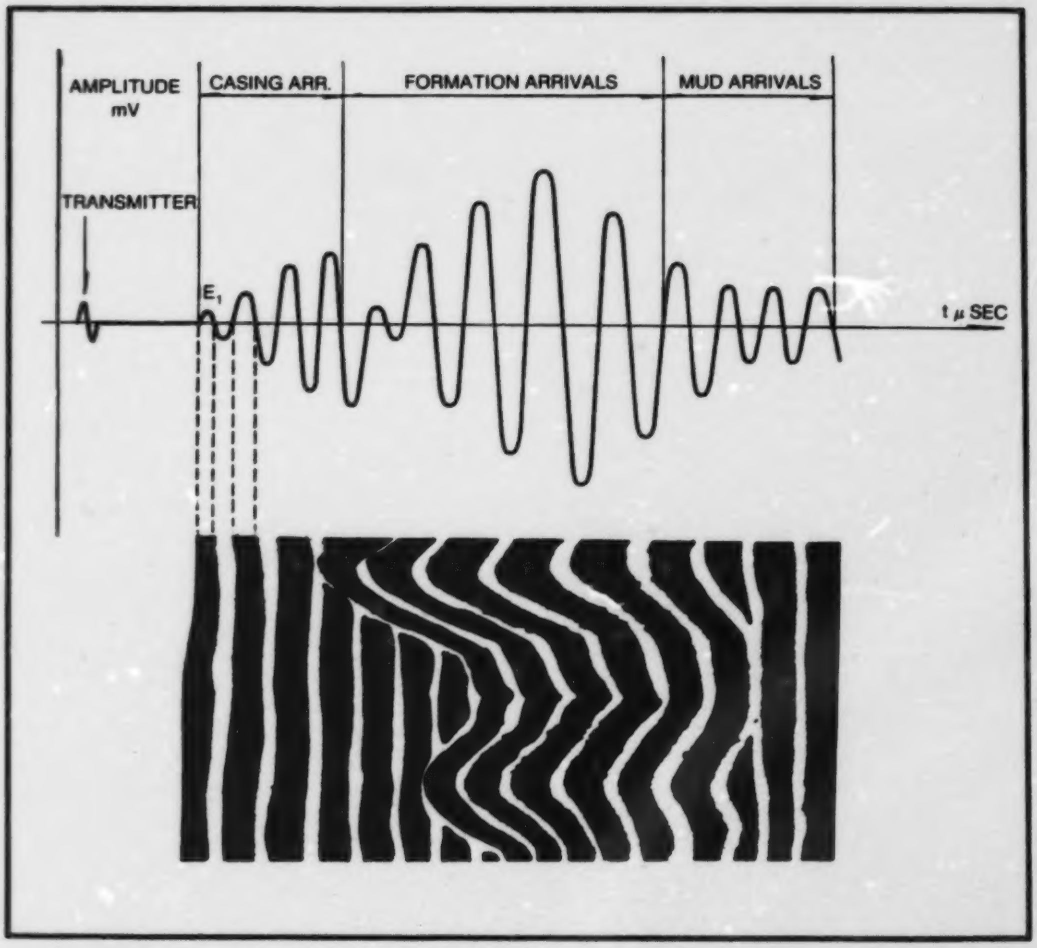

Figure 80. Principle of operation of the variable density log (Schlumberger, 1976).

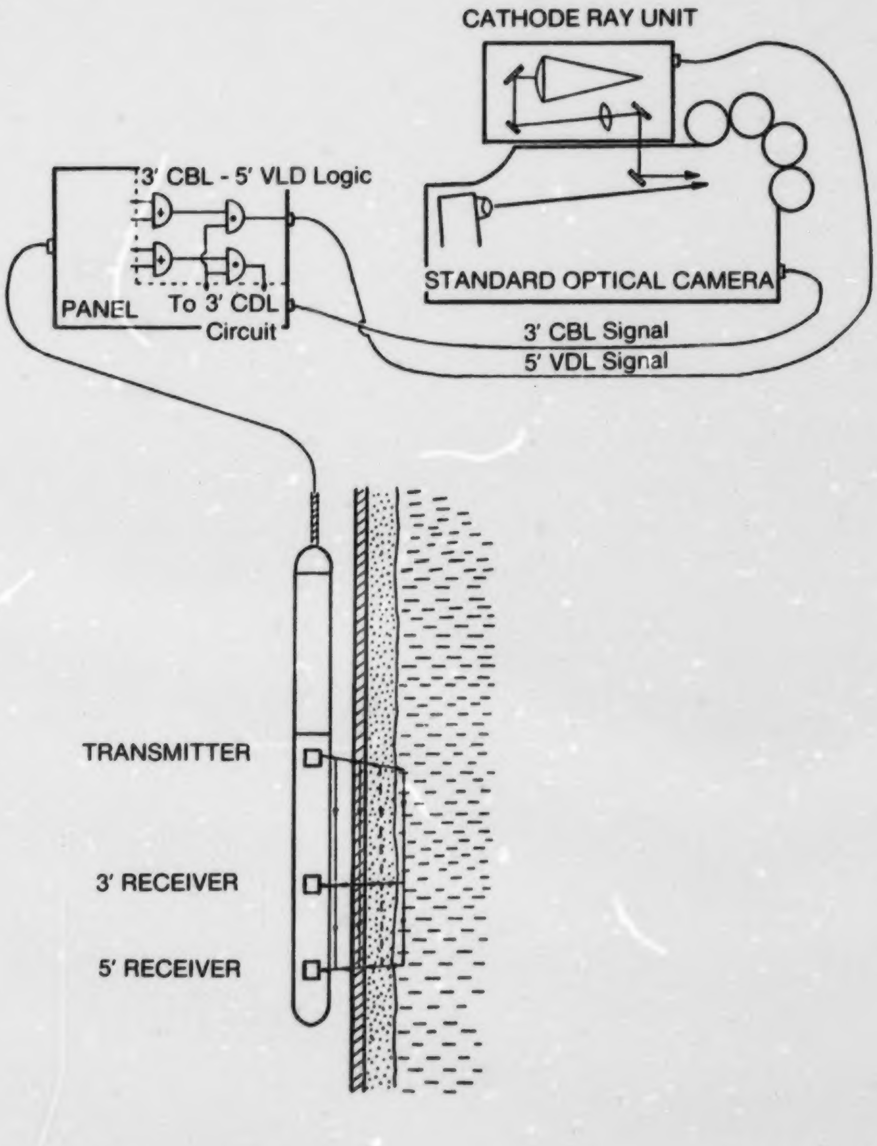

Figure 81. Diagram of equipment used for recording CBL-VDL combination (Brown et al., 1970).

the attenuation rate of casing arrival. The longer spacing is normally used for a variable density log output (VDL) which more clearly depicts formation arrivals in well bonded intervals (Fertl et al., 1974).

The cement bond logging tool ranges in outside diameter from 1 1/8 inches to 3 5/8 inches depending on the design. The length of the tool varies by manufacturer and tool configuration, but ranges from 10 to 22 feet. Some tools can be used in downhole environments up to 400°F and at maximum pressures of 20,000 psi.

In cement bond logging, the transmitter emits a series of pulses at a fixed frequency which normally ranges from 15 to 30 kHz depending on tool design. The pulse rate also varies with tool design but ranges from 10 to 60 pulses/sec and may be able to be varied at the site (Fertl et al., 1974). After travel through the appropriate combination of borehole fluid, casing and formation, the acoustic signal is picked up by the receiver(s). The measurements at the receivers are made during a specified interval called a gate. The gate has specific beginning and ending time boundaries which are referred to as the gate width (Ransom, 1975). Cement bond logging tools have two different gating systems: fixed and floating. In a fixed gate CBL, the gate width and the time the gate opens after the transmitter sends out a signal are fixed by the operator. The amplitude of whatever signal is present is recorded while the gate is open (Fertl et al., 1974). In contrast, with a floating gate, the gate remains open until an amplitude high enough to trigger the tool causes it to close. This response is recorded as transit time. The amplitude to which the gate responds is called a bias setting and must be set high enough to avoid interference from sources such as cable noise (Fertl et al., 1974). Figure 82 shows a diagram of the response of the two gating systems. Because the gating system used has a direct effect on the interpretation of the log, this is an important feature of tool design. Table 20 shows a summary of characteristics of typical cement bond logging tools and their design characteristics.

Froelich et al. (1982) describe the next generation of cement evaluation tools (CET) which are being designed and marketed to overcome some of the design and interpretation difficulties with cement bond logging tools. The CET tool is 3 3/8 inches in diameter and made for use in 4 1/2 to 5 1/2 inch casing; a 4 inch diameter tool is available for use in 5 1/2 to 9 5/8 inch casing. Eight transducers are helically arranged at 45° to one another on the tool to receive signals generated by a high frequency transducer with frequencies ranging from 300 kHz to 600 kHz (Figure 83). The transducers measure the decay of the ultrasonic echoes. The resultant log is a three-track output which is easy to interpret and which provides a display of cement distribution around the casing.

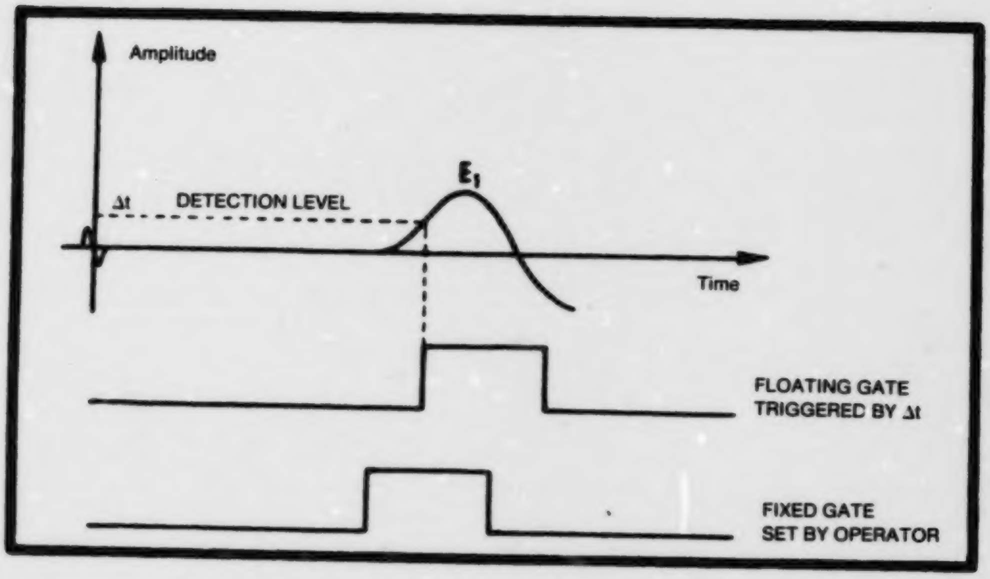

Figure 82. Diagram showing response of fixed and floating gating systems (Schlumberger, 1976).

TABLE 20. SUMMARY OF CHARACTERISTICS OF TYPICAL CEMENT BOND LOGGING TOOLS (FERTL ET AL., 1974)

Logging Company	Tool OD (in)	Type of Gate	Tr Spacing (ft)	Transmitter Frequency (KH)	Pulse Rate (pulse/sec)	Gate Width (sec)
A	3-3/8	Floating time, fixed or floating amplitude	3	20	20	25-100
	3-5/8	Fixed amplitude, floating time	3, 5	20	20	25
	1-11/16	Fixed amplitude	3	30	20	15-20
		Floating time	5			
B	3-5/8	Floating time, fixed amplitude	3, 4, 5, 7	20	15	50
	3-5/8	Fixed	3	20	60	50
	3-5/8	Fixed	3, 4, 5	20	60	50
	2-1/8	Fixed	3, 5	20	60	50
	1-11/16	Fixed	4	20	60	50
	3-3/8	Fixed	3, 4, 5	20	60	50
C	2-5/8	Fixed	4	20	20	200
	1-1/8	Fixed		30		
D	1-3/4	Fixed	4	15	10	200

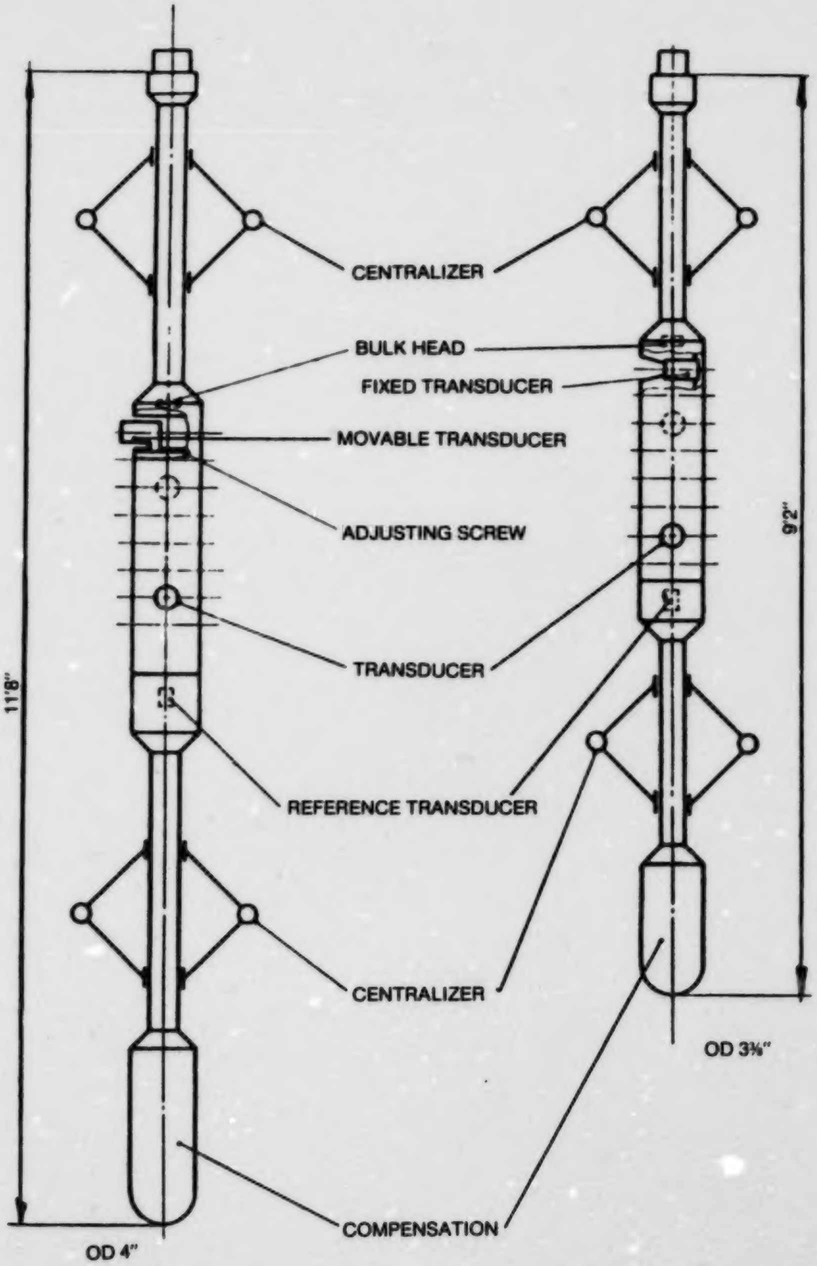

Figure 83. Diagram of the cement evaluation tool (Froelich et al., 1982).

PROCEDURE

Cement bond logs are performed on injection wells which have a cemented casing. In wells which have tubing, the tubing must be removed before the log can be run. The log may run 1) by repressurizing to injection pressures, 2) at higher or lower pressures or 3) without pressure. It may be necessary to perform the log more than once or at different pressures to avoid false interpretation due to micro-separations which decrease the amplitude of the casing signal, resulting in casing signals that are too large (McGhee and Vacca, 1980). According to McGhee and Vacca (1980), microseparations or a microannulus may be caused by a number of factors including:

- lowering the casing fluid level,

- pressure testing casing,

- holding surface pressure on casing during cement set, and

- circulating tool casing fluid immediately before logging.

By maintaining the correct fluid pressure inside the casing, anomalous results can be avoided. This may necessitate the installation of a pressure control assembly before the log is run. The presence of gas in the casing fluid will also cause unpredictable increases in transit time; therefore the casing fluid must be free of gas to obtain a meaningful log (McGhee and Vacca, 1980).

A cement bond log is made by lowering a centralized tool to the depth of interest. A minimum of three centralizers is recommended to avoid interpretation problems due to excentering (Fertl et al., 1974). The well is logged at a speed of approximately 0.5 feet per second over the zone of interest. Maximum logging speeds should not exeed 1 foot per second (Fertl et al., 1974). A continuous log is made as the tool emits pulses of signal and the acoustic signal is received by the recorder(s). The signal is processed at the surface on logging film and recorded in the CBL or CBL/VDL format (Muir and Rollman, 1970).

Care should be taken to ensure that the gain setting for the gating system is chosen properly. Too low gain settings result in reduced amplitude recording and improper interpretation (Fertl et al., 1974).

INTERPRETATION

Correct interpretation of cement bond logs is dependent on the specifications of each tool. Cement bond logs run in the same well with different tools will produce different logs. Therefore it is extremely important that a professional log analyst perform the interpretation based on the tool as well as knowledge of conditions within the well.

Cement bond logs are interpreted by observing the trace of the cement bond log or the CBL/VDL combination. Typical log responses for the four most common situations have been described in detail by Brown et al. (1970) and are discussed below.

Uncemented Casing

Uncemented casing permits most of the acoustic wave to travel through the casing with a minimum of signal attenuation. Formation signals are weak or non-existent. The CBL and VDL characteristics are:

- large casing arrivals,
- very weak or no formation arrivals,
- clear chevron patterns at the collars,
- slight increase in travel time and a decrease of CBL amplitude at the collars, and
- no change in arrival time versus depth.

Figure 84 illustrates a typical CBL and VDL output for uncemented casing. The chevron displacement shows the location of casing collars and the straightness of the VDL output indicates proper centering of the tool.

Good Casing Bond and Good Formation Bond

When both the casing and the formation are bonded to the cement, the acoustic energy is transmitted efficiently to the formation. This results in little signal travel through the casing. Characteristics of such a situation would be:

- weak casing arrivals, and
- strong formation arrivals if formation attenuation is not high.

Figure 85 illustrates a typical CBL and VDL response for good casing and formation bonding. The CBL shows low amplitude readings and the VDL confirms this indication by showing weak casing arrivals and strong formation signals. Formation signals are identified on the VDL as wiggly lines which are caused by the variation of formation transit time with depth.

Good Casing Bond but Poor Formation Bond

When a casing-cement bond is present, but a good cement-formation bond is not present, the casing signal will be attenuated by the cement but little energy will be transmitted to the formation. The characteristics of this situation would include:

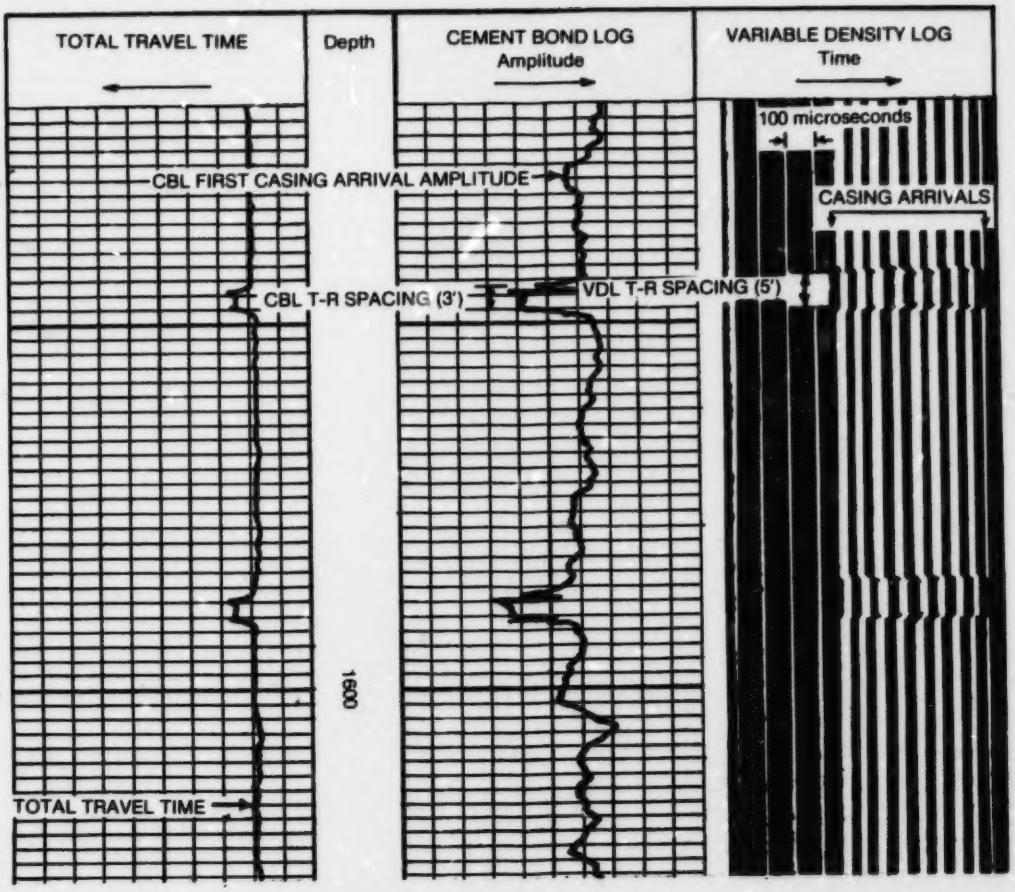

Figure 84. CBL/VDL log showing uncemented casing (Brown et al., 1970).

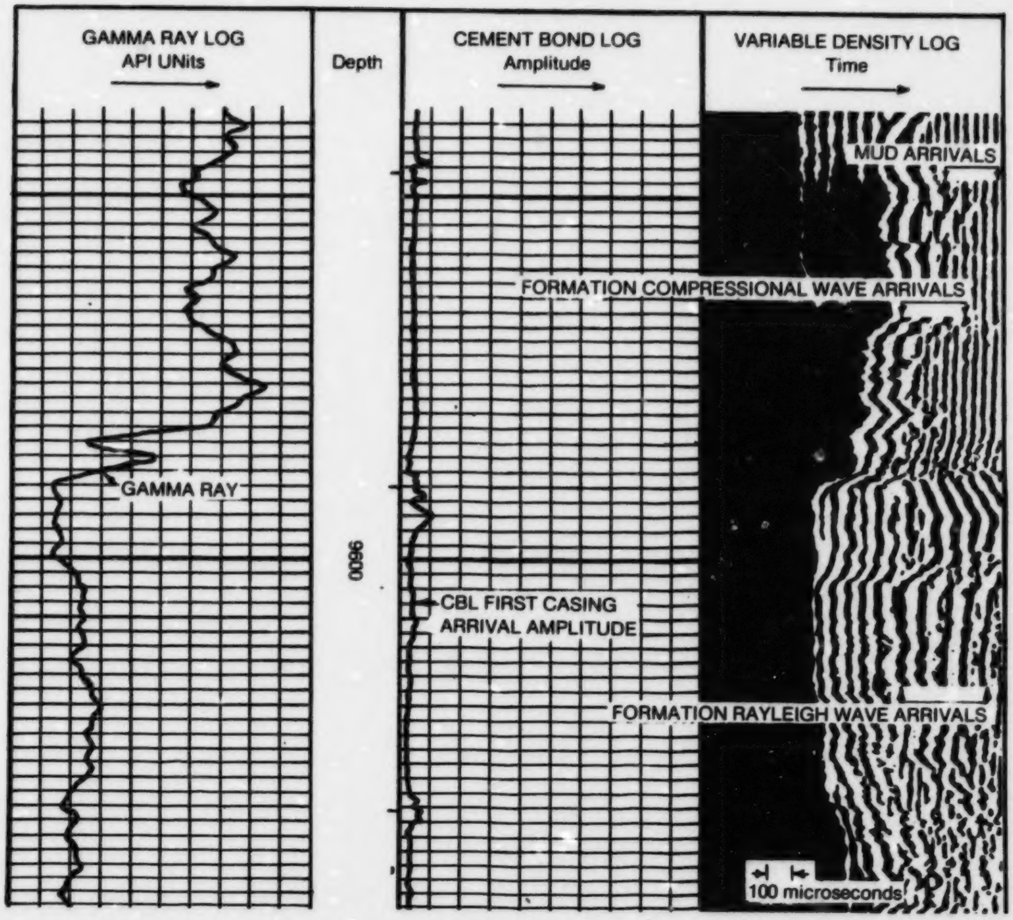

Figure 85. CBL/VDL log showing good casing-cement and cement-formation bond (Brown et al., 1970).

- weak casing arrivals, and
- weak or no formation arrivals.

Figure 86 shows good casing-cement bonding with poor cement formation bonding. The CBL amplitude is low, however the VDL does not show a clear formation arrival. Thus, poor cement-formation bonding is suspected.

Microannulus or Channeling

In situations where a small annulus gap forms between a casing and cement but the casing is well cemented, a microannulus exists. This microannulus may not affect the ability of the cement to prevent fluid migration, but will affect the results of a cement bond log. The results for both a microannulus and channeling (which permits fluid migration) are characterized by:

- moderate casing arrivals, and
- moderate formation arrivals.

Because the signal response is the same, the difference between a microannulus and channeling is most commonly distinguished by performing another log with the casing pressurized. If channeling exists, pressurizing the casing produces little or no change in the CBL or VDL. Figure 87 illustrates the CBL/VDL response for a microannulus before and after casing pressurization. When the casing is pressurized, the casing arrivals are weakened and the formation arrivals are strengthened. Another way to differentiate between a microannulus and channeling is to observe the length of casing over which the condition occurs. Typically, the microannulus will be evident over a longer section while channeling occurs for a shorter distance (Brown et al., 1970).

The results portrayed on a cement bond log may also be influenced by such factors as the type of gating system in the tool, excentering of the tool, cycle skipping and transit time stretch. The two different types of gating systems are detailed in the equipment section. Figure 88 shows the effect of each system on a CBL log run in the same well. By observing the amplitude trace, the importance of understanding the gating system can be appreciated. Excentering of the tool may also produce erroneous cement bond logs. Figure 89 illustrates the effect of performing the logging operation with the tool both properly and improperly centered.

Cycle skipping and transit time stretch are two normal responses which may occur during logging operations. Transit time stretching is a function of the wavelength of the transmitter and is caused by variations in the casing signal energy at the receiver. This phenomenon can be identified on the log for proper interpretation.

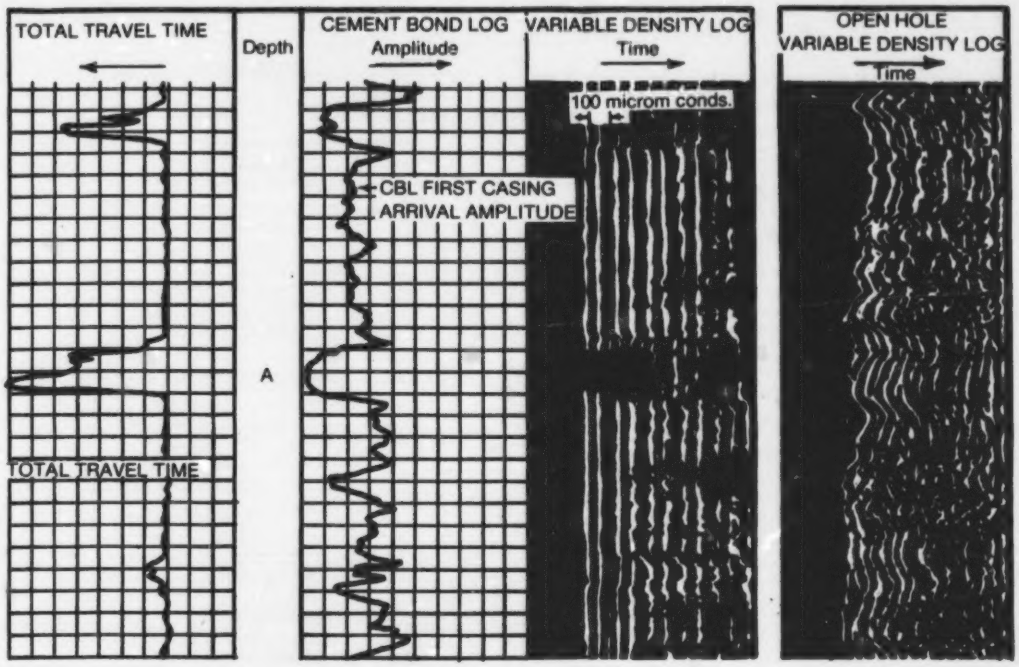

Figure 86. CBL/VDL log showing good casing-cement bond but poor cement-formation bond at level A (Brown et al., 1970).

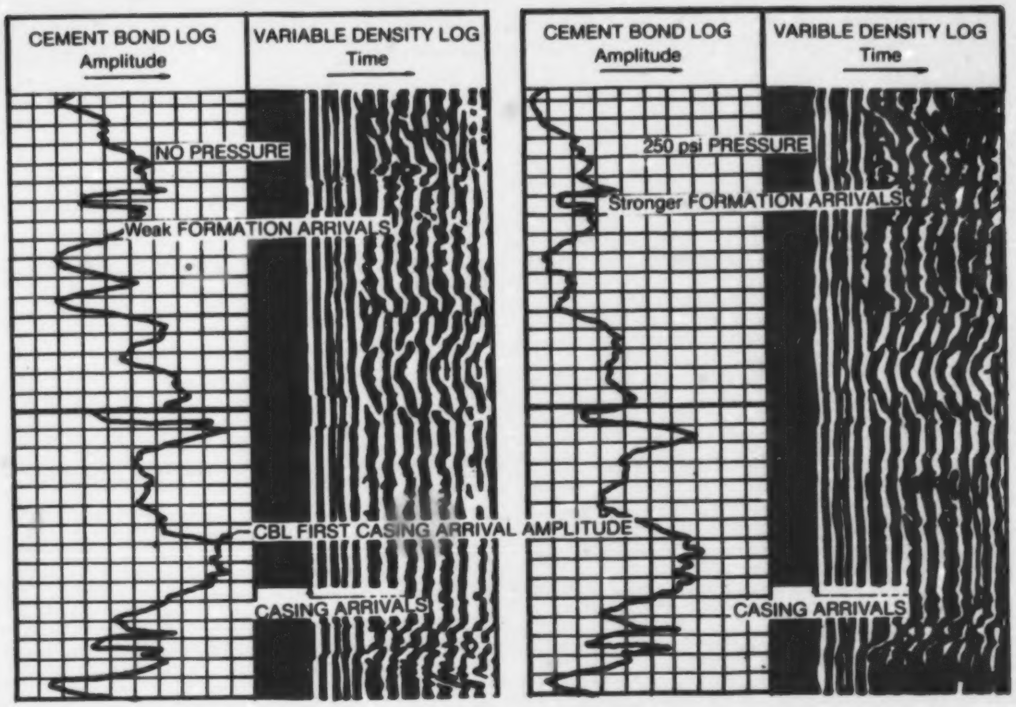

Figure 87. CBL/VDL logs showing response of microannulus runs with and without pressure in the casing (Brown et al., 1970).

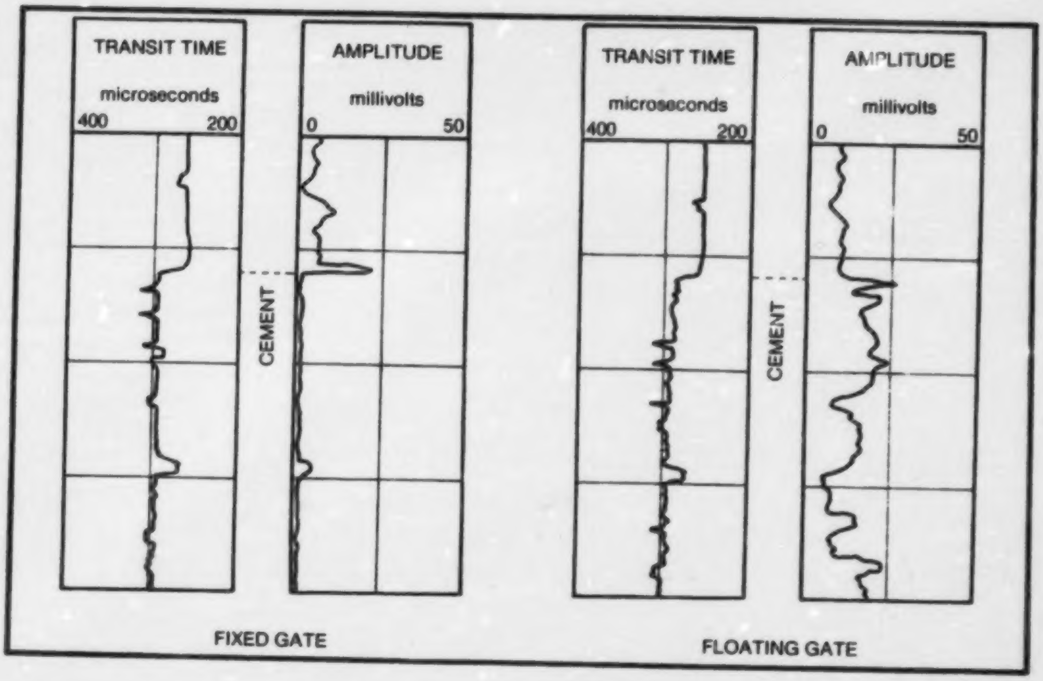

Figure 88. Effect of fixed gate and floating gate on the same log (Schlumberger, 1976).

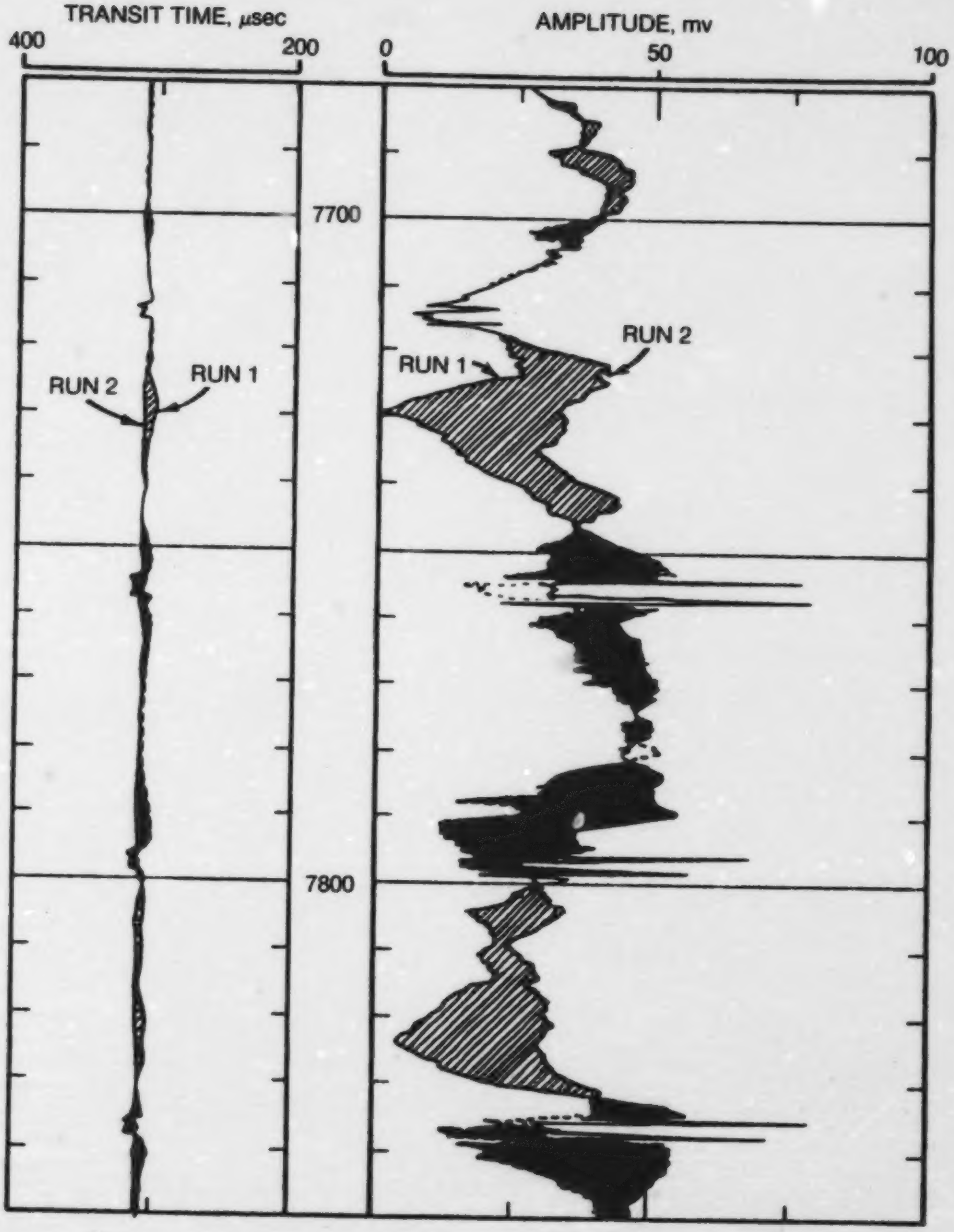

Figure 89. CBL log showing effect of proper and improper tool centering (Fertl et al., 1974).

Cycle skipping occurs when the casing signal becomes less than the transit time circuit can measure. This phenomenon can also be identified on the logs for proper interpretation.

Another way to interpret CBL is to apply what is termed a bond index, where

$$\text{Bond Index} = \frac{\text{Attenuation rate in zone of interest db/ft)}}{\text{Attenuation rate in well cemented internal (db/ft)}}$$

(Schlumberger, no date)

The bond index gives an indication of the percentage of the casing circumference which is bonded. A bond index of 1.0 represents the ideal bond and an index less than 1.0 indicates an incomplete bond. Field experience has shown that the minimum value of bond index for a hydraulic seal is 0.8 (Schlumberger, no date). However, values less than 0.8 may also be adequate in certain situations (Brown et al., 1970).

The bond index is determined by taking the lowest amplitude reading (in millivolts) on the CBL and assuming that this represents a 100 percent cement bond. By consulting a chart for the specific tool, and by knowing the amplitude and casing diameter, the attenuation rate in decibels can be read. This number is entered as the denominator in the equation (Gearhart, 1982). By multiplying the denominator by an assumed desired bond index of 0.8 and returning to the chart, it is possible to determine the values in millivolts which would constitute a poor bond. Any readings greater than this would be interpreted as having a good bond; any numbers less as having a poor bond (Gearhart, 1982). According to Brown et al., (1970) the advantage of applying a bond index is that it depends on ratios and not absolute measurements for evaluation. This minimizes the chance of interpretation errors due to unknown environmental parameters and conditions.

COST

The cost of producing a cement bond log is dependent upon the many general pricing variables outlined in Section 7. The range of specific depth and logging charges as determined by a survey of six major well logging companies in the midcontinent area of the United States are listed in Table 21. Refer to Table 7 for a listing of companies which perform this service.

ADVANTAGES/DISADVANTAGES

The cement bond log may be used in injection wells to infer the presence of channels in the cement adjacent to the casing. When properly interpreted, the cement bond log indicates the potential for

TABLE 21. TYPICAL DEPTH AND LOGGING CHARGES FOR CEMENT BOND LOGGING

Depth Charge	Low	High
per foot	$0.21	$0.35
minimum	$300	$700
Logging Charge	**Low**	**High**
per foot	$0.20	$0.35
minimum	$250	$700

fluid movement and may point out areas that need to be investigated using other logging techniques.

There are many disadvantages to using a cement bond log. First, the log cannot be used to find leaks or determine actual fluid movement behind the casing. Second, when injection wells are completed with tubing, the tubing must be removed before the log can be run. However, the greatest disadvantages are the wide range of parameters which can affect the readings and interpretation of cement bond logs. Cycle skipping, transit time stretching, excentering, design of gating systems, spacing of tool transmitter-receivers, the presence of a microannulus, the type of borehole fluid as well as the conditions during cementing and pressures of operation are some of the variables which must be taken into consideration during interpretation since they may cause a channel to be missed. Because logging tools are not standardized, the log must be interpreted for that particular tool and logs run by one company should not be interpreted by another.

EXAMPLES

Figure 90 is an example of a channel in the cement which was located and solved through the use of a CBL/VDL bond log. The CBL on the far right shows a high amplitude signal which is indicative of a poor casing-cement bond. In the interval from 8950 to below 9050, the VDL confirms the results of the CBL display through the presence of straight bands delineating casing signals on the far left. After the problem was identified, the casing was perforated and a cement squeeze job performed. The CBL/VDL log after the squeeze indicates that the problem has been solved as evidenced by the lower amplitude on the CBL and the elimination of the straight bands on the VDL.

Additional examples have been included as part of the interpretation section.

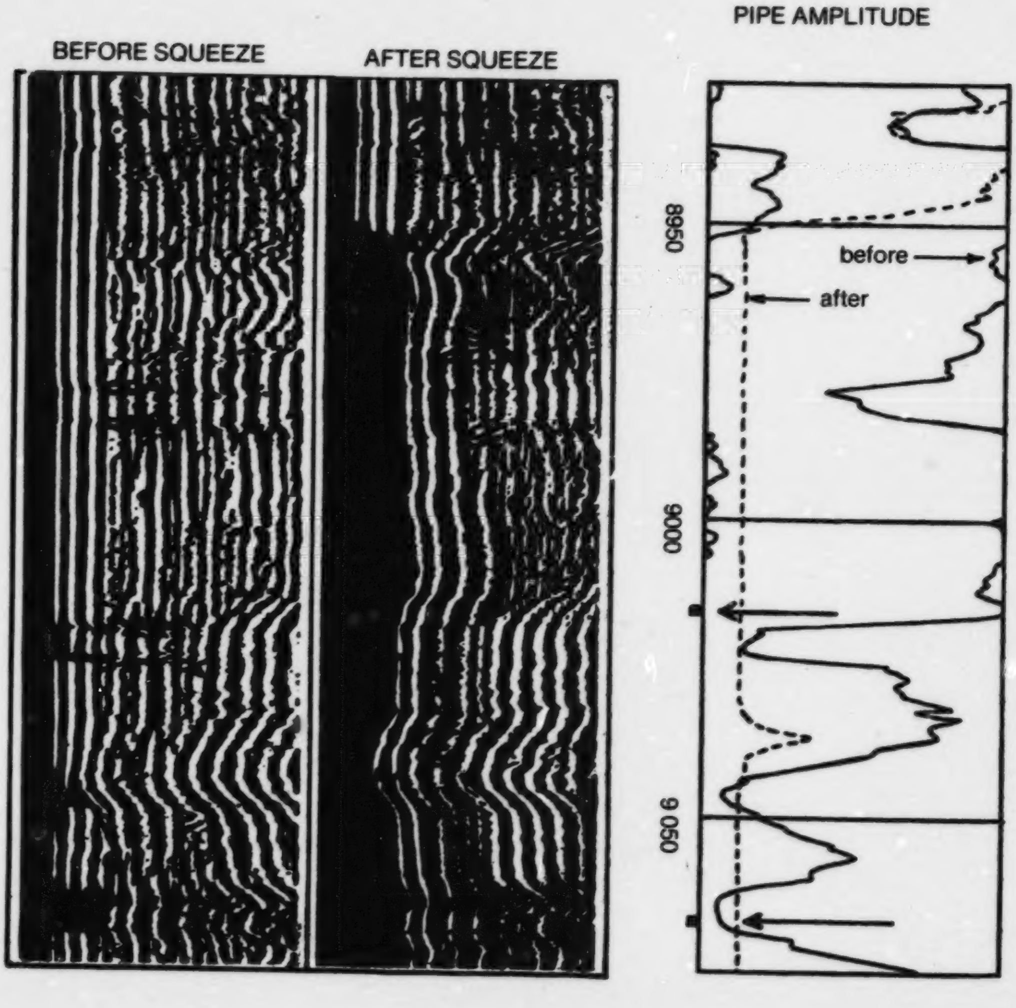

Figure 90. Elimination of a channel by cement squeezing (Walker, 1968).

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SECTION 18

OTHER MECHANICAL INTEGRITY TESTING METHODS

INTRODUCTION

In addition to the methods described in previous chapters, there are several other methods which could potentially be useful in testing the mechanical integrity of an injection well. This chapter briefly summarizes these methods, which are either so highly specialized or so new that limited or no field data are available to assist in evaluating their usefulness. Some of these methods are variations of existing logging methods and others are applications of methods from other fields. With additional laboratory and field testing, some of the methods described in this chapter could prove very useful in mechanical integrity testing.

NATURAL GAMMA LOGGING

Natural gamma logging measures the natural gamma radiation of formations adjacent to the wellbore, and is one of only a few techniques which can be utilized to log through casing. Changes in the intensity of natural gamma radiation are commonly associated with lithologic changes. Shale or clay, for example, emit more natural radiation than a clean quartz sand. This phenomenon is due to the presence of higher concentrations of potassium, thorium or uranium isotopes in clay-rich deposits. As these isotopes decay, they emit gamma radiation that can be detected by a natural gamma logging tool.

Campbell (1951) noted the occurrence of increased natural radioactivity in zones of perforations in producing oil wells. He attributed this phenomenon to the presence of a "radioactive crust" that forms from the buildup of mineral scale resulting from the reaction of salt water with iron oxides in metal well casings. Natural gamma logs have been successfully used to locate such zones in producing wells in which appreciable quantities of salt water are produced along with petroleum.

Killion (1966) suggests that similar naturally radioactive deposits can result from prolonged fluid migration in channels in the cement behind well casing, and further suggests that these deposits can be logged using gamma logging techniques. By correlating a recently run natural gamma log with a previously run gamma log and electric log, Killion was able to detect what he interpreted to be zones of fluid migration outside the casing of a producing oil well.

Figure 91 shows an anomaly which appeared in a producing well over the course of six years, as the well produced increasing amounts of water. The well was taken out of service and a new gamma log run and then compared to previously run gamma and electric logs. In the interval from about 7775 feet to 7850 feet, a radioactive anomaly was noted. This was determined to have been caused by a radioactive crust formed as salt water from a salt water sand at 7760 to 7775 feet channeled through the well bore into the production zone at 7852 to 7858 feet. In this case, the well was rehabilitated and brought back to water-free production (Killion, 1966). Keys (personal communication, 1983) notes that for this method to be successful, any comparison of gamma counts must be done either using the same probe or normalizing the response of a different probe.

While this logging technique has not been reported as having been used in injection well applications, clearly the same principles apply and the technique could be useful in wells for which a baseline gamma log is available. However, because no work has been done in this area since the initial work of Killion, additional field testing of this method would be desirable.

CONTINUOUS OXYGEN ACTIVATION LOGGING

Wichmann et al. (1967) reported on a method for determining the presence of fluid flow behind casing that utilized the principle of oxygen activation. This technique involves the "tagging" of any fluid containing oxygen (O^{16}) by making it radioactive; in effect, this amounts to using oxygen as a tracer. When an O^{16} atom is irradiated with neutron radiation from a downhole source, the atom transmutes into a radioactive nitrogen (N^{16}) atom. The N^{16} atom decays with a half-life of 7.13 seconds, emitting a beta particle and high-energy gamma radiation that can be detected by a gamma ray detector.

This principle was utilized by Paap and Arnold (1977) and Paap et al. (1977) in the development of a water flow monitoring system that measures the direction, linear flow velocity, volumetric flow rate and radial position of water flowing vertically behind casing. The system utilizes a neutron radiation source which pulses neutron radiation outward in all directions (Figure 92). A pair of longitudinally spaced gamma ray detectors is used to detect the movement of irradiated O^{16} behind the casing in a manner similar to that used in radioactive tracer techniques (Section 16). The flow parameters of interest are computed from the energy and intensity response of the detectors. Oxygen activation differs from other tracer techniques in the sense that the tracer, N^{16}, is "manufactured" in the water (Arnold and Paap, 1979). This essentially eliminates several of the disadvantages of using radioactive tracers (i.e. handling of radioactive materials), and allows for a more quantitative description of flow parameters than is possible with conventional tracers (Arnold and Paap, 1979).

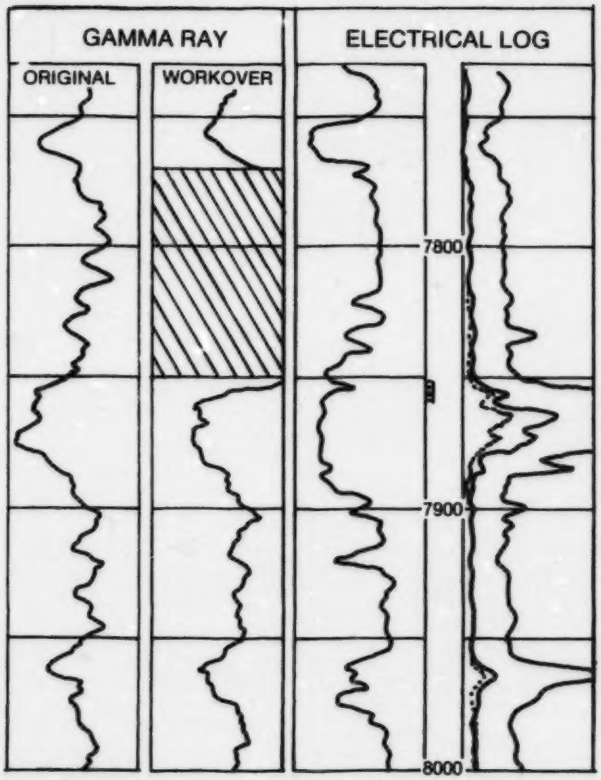

Figure 91. Comparison of an old gamma log with a more recent gamma log and electric log run in the same well (Killion, 1966).

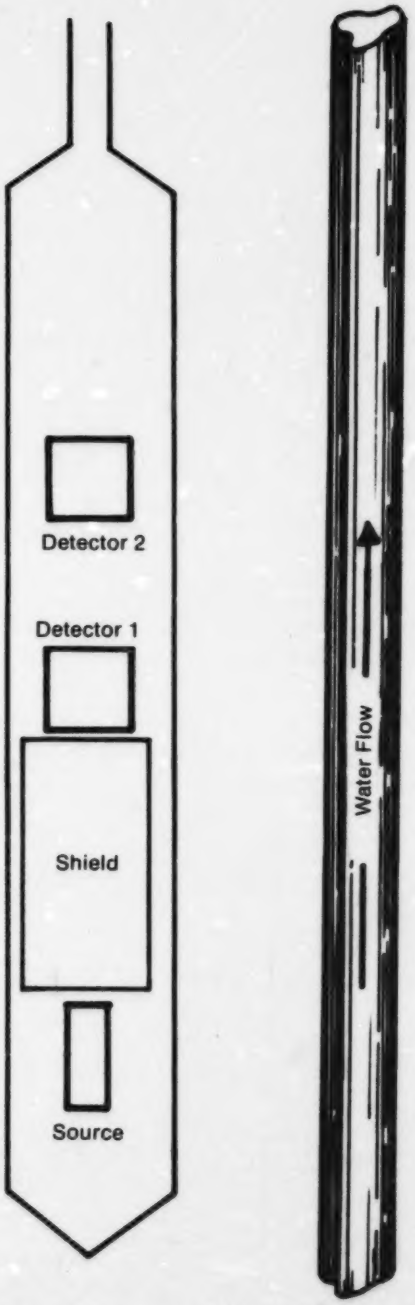

Figure 92. Dual-detector flow sonde and hypothetical channel water flow (Arnold and Paap, 1979).

Field testing of this technique has proven promising, but it is not yet, at the time of printing of this report, widely available through well service companies.

MAGNETIC CASING LOGGING

Patterson et al. (1971) describe a system developed for logging tension-type casing failures in steam injection wells. The system was developed after it was noted that during borehole television surveys of these wells, distortion of the picture on the television monitor would occur when the downhole camera passed by tension failures in the casing. The actual theory behind the operation of the device is complicated, but in simple terms depends upon the fact that a well casing acts like a very long magnet, with the bottom of the casing acting as one pole and the top of the casing acting as the other pole. When a tension failure occurs and the casing is separated, the once-long single magnet is broken into two smaller pieces. The magnetic lines of flux produced by the casing separation set up an external magnetic field across the separation; this anomaly can be detected by a tool which operates in a manner similar to that of a casing collar locator. The tool utilizes a search coil which, when passed through a magnetic field, generates a voltage that is sent to the surface via a shielded wireline. An example of the resulting log, which plots the magnitude of the voltage created when the tool passes through a magnetic field with respect to depth, is shown in Figure 93.

Several magnetic casing logging tools were tested by Patterson et al. (1971) under field conditions in steam injection wells. The final design of the tool which was developed for field use is shown in Figure 94. This tool was designed to fit through standard 2 3/8-inch injection tubing, and thus could be used in a well without removing the tubing. However, the tool can only detect areas of the casing which have pulled apart (or nearly so) and casing collars; it does not detect minor casing flaws or vertical splits. Thus, its applications in mechanical integrity testing appear to be limited.

VOLUMETRIC SCANNING

Broding (1981) describes a process of measuring the physical response of rock formations or well casing in a borehole by scanning with high-frequency acoustic energy in the lateral, vertical and azimuthal directions. The method of operation of the volumetric scanning (VS) survey is similar to that of the borehole televiewer (Section 14), in which an acoustic transducer is rotated in a well at three revolutions per second and pulsed at 485 times per revolution. The VS differs from BHTV in that it pulses acoustic energy at 512 times per revolution and it utilizes three scans: a rotational scan and a depth scan like the BHTV, and an outward scan which provides a third dimension. The acoustic signal is reflected off the casing wall back to the transducer, where it is received; the resulting signal,

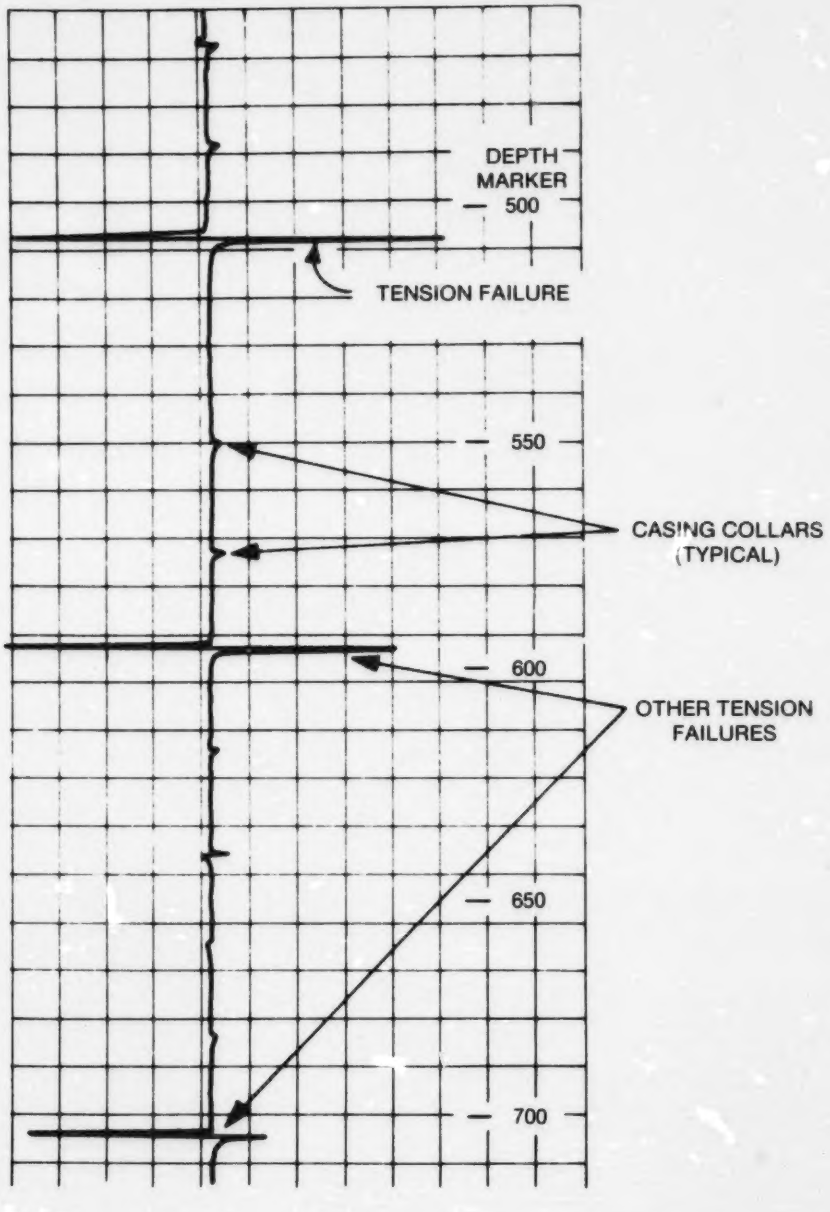

Figure 93. Log depicting results of a magnetic casing log (Patterson et al., 1971).

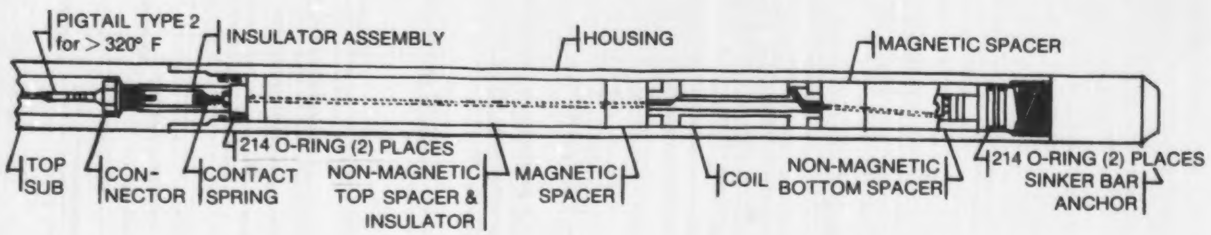

Figure 94. Final design of the magnetic casing logging tool (Patterson et al., 1971).

which consists of both signal amplitude and travel time, is recorded on magnetic tape at the surface. The recorded image of casing reflectance has the general appearance of a true three-dimensional image of the well casing. The image can be tilted at different angles (Figure 95) or rotated (Figure 96) to assist in the interpretation of the casing image. This results in the capability of essentially holding the casing in the viewers' hand and viewing it from all directions (Broding, 1981).

While Broding has successfully applied the VS to casing inspection with success, the use of this technique is limited by lack of additional field applications and inavailability of equipment.

HELIUM LEAK TEST

Dewan (1983) describes a method of leak testing that utilizes helium, an inert, non-toxic, relatively inexpensive gas that readily diffuses through microscopic leaks because of its small molecular size. The testing procedure consists of pressurizing an enclosure to be tested (i.e. and injection well casing or tubing) with a mixture of helium and air to above atmospheric pressure and then "sniffing" the outer surface of the enclosure with a probe capable of sensing very low concentrations of helium (i.e. 1 part per million) in air. While this testing method is utilized in other applications, it has not been applied to mechanical integrity testing of injection wells.

A method for testing injection wells utilizing this technique has been proposed by Dewan (1983):

After the well is taken out of service, a mixture of 90 percent nitrogen (or air) and 10 percent helium would be injected into the tubing at about 1000 psi pressure in a quantity sufficient to fill the well to a point just below the packer. About 50 cubic feet of gas mixture would be required for a 2000-foot well with 2-inch tubing, and about 12 hours would be required for the helium to displace the water in the tubing into a formation normally taking 50 barrels per day. As the helium/water interface progresses downward, any tubing leak encountered would allow helium to enter the casing-tubing annulus. The helium would diffuse upward and collect at the top of the annulus, where it could be detected with a gas detector probe. Once the helium/water interface reaches a level below the packer, any leak through the packer in the casing-tubing annulus or in the cement in the casing-borehole annulus would likewise allow helium to enter the annulus, diffuse upward, and be detected. Figure 97 shows the helium leak test arrangement proposed by Dewan for so-called "non-standard" injection wells (i.e. those in which casing does not extend to total depth).

Because water will dissolve helium, it will hinder the diffusion of helium to the surface. Dewan (1983) notes that the solubility of

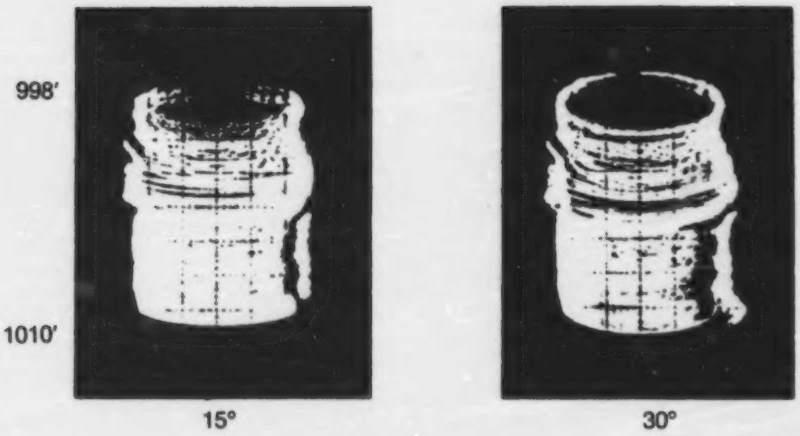

Figure 95. Casing damage: tiled polar image (Broding, 1981).

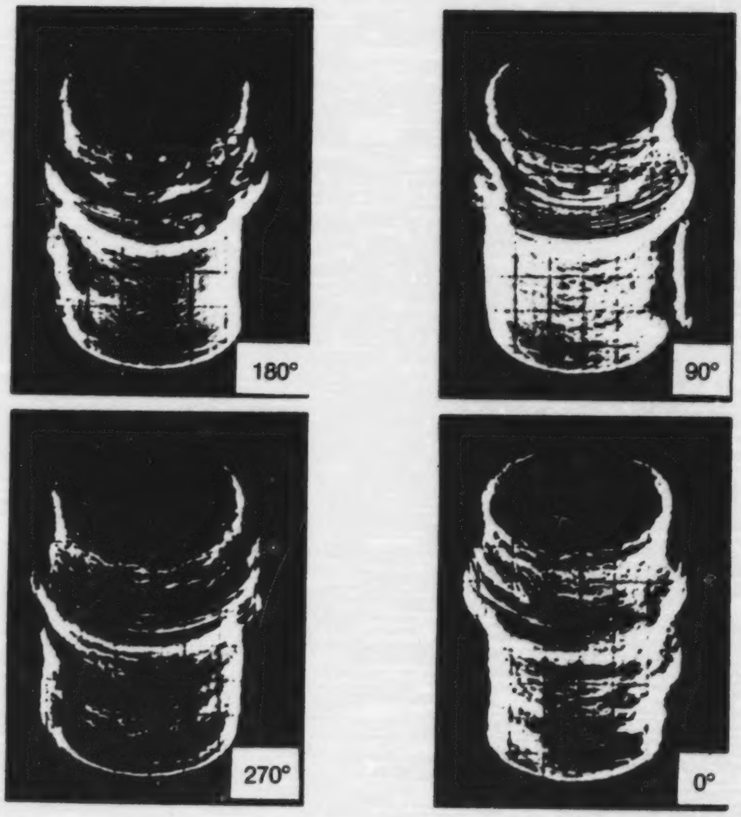

Figure 96. Casing damage: polar scanning with sectioning and rotation (Broding, 1981).

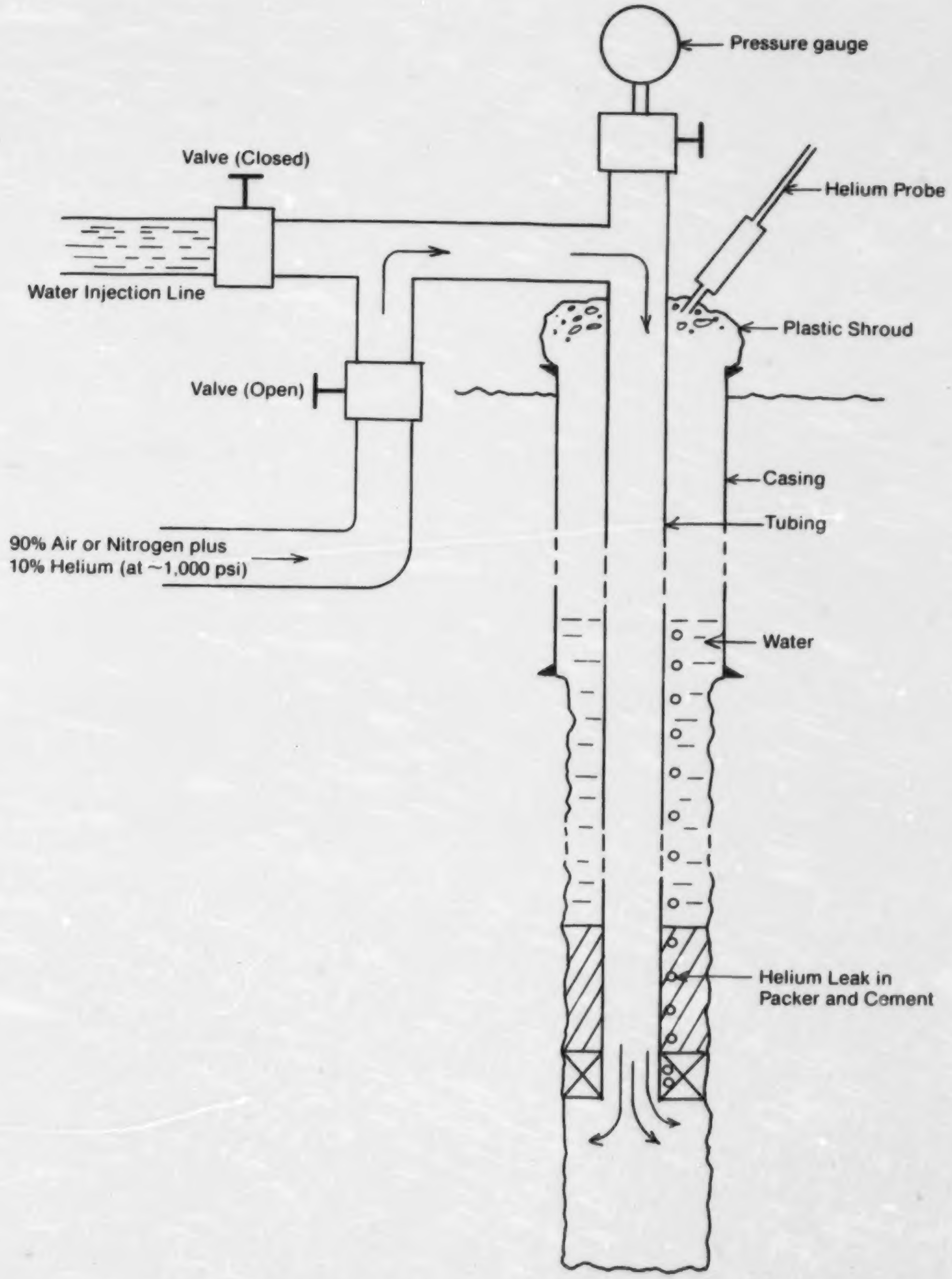

Figure 97. Proposed helium return leak-test arrangement (Dewan, 1983).

helium in water, at atmospheric pressure and 86°F, is 0.84 cubic feet of helium per 100 cubic feet of water, and that the solubility increases in direct proportion to the pressure. He estimates that the rate at which excess helium would progress upward through a column of water is about 2000 feet per hour. The optimum situation is that in which there is no water or other fluid in the annulus, only air, but this is uncommon in injection well operations.

While helium leak testing is among the most sensitive leak detection systems known and it is employed in many other applications, its usefulness in mechanical integrity testing of injection wells is not proven. Both laboratory and field testing would be necessary to establish this as a viable technique for testing injection well integrity.

ON-SURFACE TUBING INSPECTION

Prior to running some of the logs discussed in this report, it is required that the injection tubing be removed from the well. While the tubing is at the surface, it can be inspected by any one of several methods.

One device, described by Hauldren (1977) inspects tubing for stress cracks and flaws as it is pulled from the well. This device utilizes a series of ultrasonic search units that each send acoustic energy through the tubing. Receiving transducers are stabilized and kept at the proper detection angles by a series of tension wheels. The transducers detect discontinuities both transverse and parallel to the longitudinal axis of the tubing. Wall thickness of the tubing is also determined.

Another type of testing method, described by Tompkins (1972) provides an overall determination of the quality of the tubing. It uses a gamma radiation detector positioned inside the tubing and a gamma radiation source, which pulses gamma rays as the tubing is rotated and pulled through the detector, on the outside of the tubing. Flaws and weak areas in the tubing are determined by comparing the amount of radiation detected at the probe against a standard for a given wall thickness.

Suman and Ellis (1977) describe a method refered to as the electromagnetic diverted flux search coil testing system. The principle behind this system is relatively complex, but is similar to that described for the electromagnetic casing inspection methods outlined in Sections 10 and 11. A magnetic flux field is induced into the wall of the tubing. The field flows in one direction through the tubing and diverts around any imperfections (Figure 98). Search coils, as shown in Figure 99 detect these diversions in the induced magnetic field and record the magnitude and pattern of the diversion (Suman and Ellis, 1977).

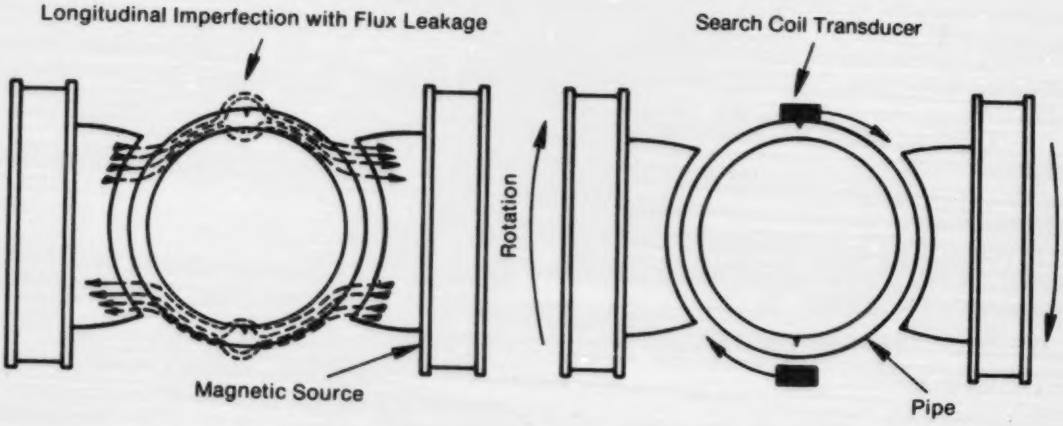

Figure 98. Diagram of transverse electromagnetic diverted flux search coil system (Suman and Ellis, 1977).

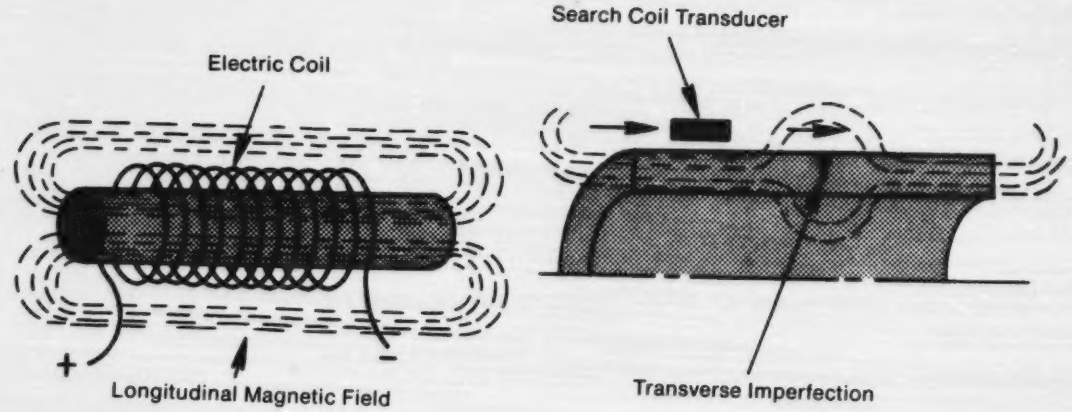

Figure 99. Diagram of longitudinal EDFSC system used to detect transverse imperfections (Suman and Ellis, 1977).

Variations in metallurgical properties of tubing can be detected using electronic metal comparitors, which electronically compare induced electromagnetic eddy currents in the tubing with the response of a known grade of material used as a standard. Variations in the balance between the standard and the injection tubing indicate a change in the metallurgical properties of the tubing. This method only provides a qualitative measure of differences in tubing properties and does not define the extent or magnitude of any problem present (Suman and Ellis, 1977).

PHOTOGRAPHIC LOGGING

Photographic logging was originally developed to locate and evaluate fractures in the uncased portion of wells (Dempsey and Hickey, 1958). With refinements in the techniques and equipment, photographic logging has been used for detailed casing inspection.

Photographic logging produces a "snapshot" photographic image using a light source, a borehole camera, and light-sensitive film. The image is actual documentation of the condition of the casing rather than derived information. A simple visual examination of the problem provides valuable information often lacking when conventional logging techniques are used.

Borehole cameras have become nearly obsolete with the advent of newer technology, such as the borehole television (Section 13) or the borehole televiewer (Section 14), but they may still be useful for specialized applications in injection wells.

There are several types of borehole cameras available for use in inspecting the inside surface of the well casing. They are, from the simplest to the most complex:

1) monocular - single-shot camera,

2) monocular - multi-shot camera,

3) stereoscopic - single-shot camera, and

4) stereoscopic - multi-shot camera.

The actual design of borehole cameras varies greatly from manufacturer to manufacturer but the basic principle of their operation is the same. The camera operates by means of a shutter that exposes photographic film to a properly illuminated image. An image reflects light rays toward a camera and the reflected light rays enter the camera lens. As the reflected light rays move through the lens, they are focused onto the film plane. An iris, located within the lens, reduces the amount of light that strikes the film plane commensurate with the speed of the shutter opening and closing and the speed of the film.

In an injection well, lighting is generally provided by a syncronized electronic flash mounted just below or just above the camera lens. The field of vision (or focal length) and focus are adjusted manually at the surface for optimum picture quality and clarity based on the well design and its condition.

Film size varies, depending upon the type of camera (single-shot or multi-shot) and the physical size of the camera. Film disks (1 inch diameter) are generally used in single-shot cameras while 8mm, 10mm, 16mm or 35mm film magazines are used in multi-shot cameras. The film magazines are advanced through the film plane by means of an electronic motor drive. Film magazines range in length from a few dozen shots to up to 600 shots per magazine.

The camera system can be activated either by means of an internal timer system or electronically through a connecting cable. For single-shot cameras, the camera must be retrieved from the well and reloaded at the surface after each shot. Multi-shot cameras automatically advance the film and cock the shutter after each photograph.

Camera sizes range from 1.25 inches OD to 3 inches OD. The length of the camera varies from 1 foot to several feet. Cameras are manufactured of corrosion-resistant material, such as stainless steel; most are pressure-rated to 15,000 psi.

Stereoscopic cameras vary only slightly from monocular cameras. In the case of stereoscopic cameras, two photographs are simultaneously taken of the same image, from two slightly different viewing angles. The resulting photographs, when viewed together through a special viewer are seen as a three-dimensional image.

There are several disadvantages to using the borehole cameras in an injection well. The fluid in the well must be clear for the camera to produce a useful image. In addition, the survey cannot be conducted in high-temperature environments, as high temperatures deteriorate the film quality; the maximum operating temperature for most cameras is approximately 200°F. Also, the results of the log are dependent upon retrieval of the camera and proper film development. Photographic logging cannot provide information about the condition of the outside surface of the casing or the condition of the cement behind the casin. It can, however, provide evidence of casing damage and internal corrosion, and it is possible to recognize a leak.

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APPENDIX A

TABLES USED TO ESTIMATE THE VOLUME OF LIQUID LOST FROM A WELL (IN GALLONS) FOR A GIVEN ANNULUS PRESSURE CHANGE (LANGLINAIS, 1981)

TABLE A-1. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 7" (6.366" ID) x 4.5" ANNULUS (GALLONS) (LANGLINAIS, 1981)

	Depth (Feet)				
Change In Pressure (psi)	1,000	2,000	3,000	4,000	5,000
10	.039	.078	.116	.154	.192
25	.098	.193	.288	.381	.474
50	.196	.388	.577	.765	.952
100	.391	.773	1.150	1.524	1.898
200	.782	1.547	2.301	3.048	3.795
300	1.173	2.320	3.451	4.572	5.693
400	1.563	3.092	4.599	6.094	7.587

TABLE A-2. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 7" (6.366" ID) x 4" ANNULUS (GALLONS) (LANGLINAIS, 1981)

Change In Pressure (psi)	Depth (Feet)				
	1,000	2,000	3,000	4,000	5,000
10	.044	.086	.128	.169	.211
25	.109	.216	.320	.424	.528
50	.219	.432	.643	.851	1.059
100	.437	.863	1.283	1.699	2.115
200	.874	1.728	2.568	3.401	4.233
300	1.312	2.593	3.853	5.103	6.351
400	1.749	3.456	5.136	6.802	8.466

TABLE A-3. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 7" (6.366" ID) x 3.5" ANNULUS (GALLONS) (LANGLINAIS, 1981)

Change In Pressure (psi)	Depth (Feet)				
	1,000	2,000	3,000	4,000	5,000
10	.048	.094	.140	.185	.230
25	.118	.232	.345	.457	.568
50	.236	.466	.692	.916	1.139
100	.470	.929	1.379	1.826	2.272
200	.940	1.856	2.757	3.649	4.540
300	1.410	2.785	4.136	5.475	6.812
400	1.879	3.711	5.512	7.296	9.077

TABLE A-4. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 7" (6.366" ID) x 2⅞" ANNULUS (GALLONS) (LANGLINAIS, 1981)

	Depth (Feet)				
Change In Pressure (psi)	1,000	2,000	3,000	4,000	5,000
10	.051	.101	.150	.199	.247
25	.128	.253	.375	.497	.618
50	.257	.507	.752	.996	1.238
100	.512	1.011	1.501	1.986	2.470
200	1.025	2.022	3.002	3.972	4.940
300	1.537	3.033	4.502	5.957	7.411
400	2.048	4.043	6.001	7.941	9.878

TABLE A-5. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 7" (6.366" ID) x 2⅜" ANNULUS (GALLONS) (LANGLINAIS, 1981)

	Depth (Feet)				
Change In Pressure (psi)	1,000	2,000	3,000	4,000	5,000
10	.055	.108	.160	.211	.263
25	.136	.268	.397	.525	.653
50	.271	.534	.792	1.048	1.304
100	.540	1.066	1.583	2.094	2.604
200	1.080	2.131	3.163	4.185	5.205
300	1.621	3.198	4.746	6.278	7.808
400	2.160	4.261	6.324	8.366	10.406

TABLE A-6. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 5½" (4.892" ID) x 2⅞" ANNULUS (GALLONS) (LANGLINAIS, 1981)

Change In Pressure (psi)	Depth (Feet)				
	1,000	2,000	3,000	4,000	5,000
10	.026	.050	.075	.099	.123
25	.064	.125	.186	.247	.307
50	.127	.251	.373	.494	.614
100	.255	.503	.746	.988	1.229
200	.509	1.005	1.493	1.976	2.458
300	.764	1.509	2.240	2.964	3.688
400	1.019	2.011	2.986	3.952	4.917

TABLE A-7. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 5½" (4.892" ID) x 2⅜" ANNULUS (GALLONS) (LANGLINAIS, 1981)

Change In Pressure (psi)	Depth (Feet)				
	1,000	2,000	3,000	4,000	5,000
10	.029	.057	.085	.112	.140
25	.071	.140	.208	.275	.343
50	.142	.279	.414	.548	.682
100	.283	.558	.828	1.096	1.363
200	.565	1.115	1.655	2.189	2.723
300	.848	1.673	2.483	3.285	4.086
400	1.130	2.230	3.310	4.379	5.446

TABLE A-8. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 5" (4.408" ID) x 2⅜" ANNULUS (GALLONS) (LANGLINAIS, 1981)

	Depth (Feet)				
Change In Pressure (psi)	1,000	2,000	3,000	4,000	5,000
10	.022	.043	.063	.084	.104
25	.054	.106	.157	.207	.258
50	.107	.211	.313	.415	.516
100	.215	.424	.629	.832	1.035
200	.430	.849	1.260	1.667	2.074
300	.645	1.273	1.890	2.501	3.110
400	.860	1.697	2.519	3.333	4.146

TABLE A-9. FLUID LOSS IN GALLONS VS. PRESSURE DROP IN 7⅝" (6.95" ID) CASING x 2⅜" TUBING ANNULUS (GALLONS) (LANGLINAIS, 1981)

	Depth (Feet)				
Change In Pressure (psi)	1,000	2,000	3,000	4,000	5,000
10	.067	.132	.195	.258	.321
25	.165	.326	.484	.640	.797
50	.329	.650	.964	1.276	1.587
100	.659	1.300	1.929	2.551	3.173
200	1.317	2.598	3.855	5.100	6.343
300	1.976	3.897	5.784	7.651	9.516
400	2.634	5.196	7.710	10.200	12.686

APPENDIX B

GRAPHS WHICH DEPICT THE RESPONSE OF ANNULUS PRESSURE TO INJECTED FLUID TEMPERATURE FOR VARIOUS WELL CONFIGURATIONS (LANGLINAIS, 1981)

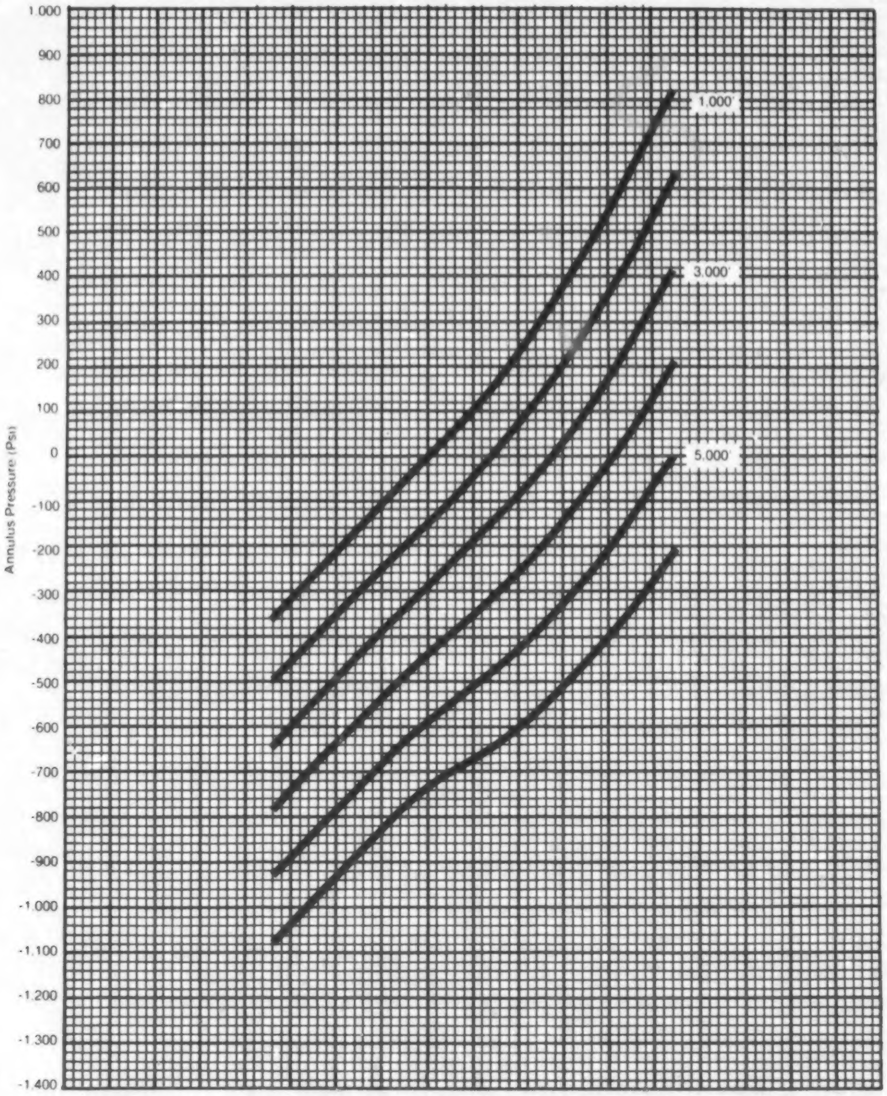

Figure B-1. Response of annulus pressure to injected fluid temperature for 7" tubing x 9⅝" casing x 12¼" borehole (Langlinais, 1981).

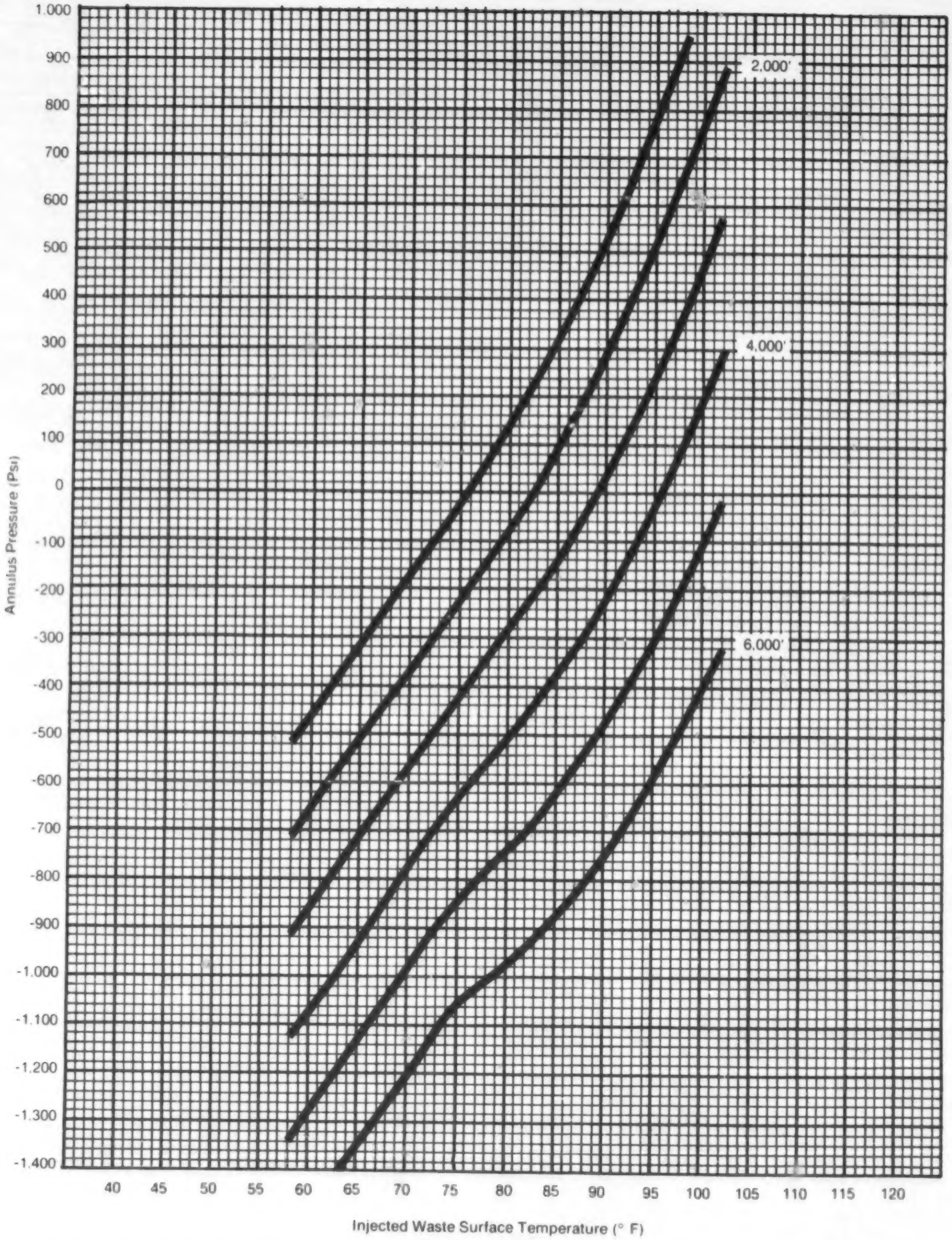

Figure B-2. Response of annulus pressure to injected fluid temperature for 3½" tubing x 7" casing x 8½" borehole (Langlinais, 1981).

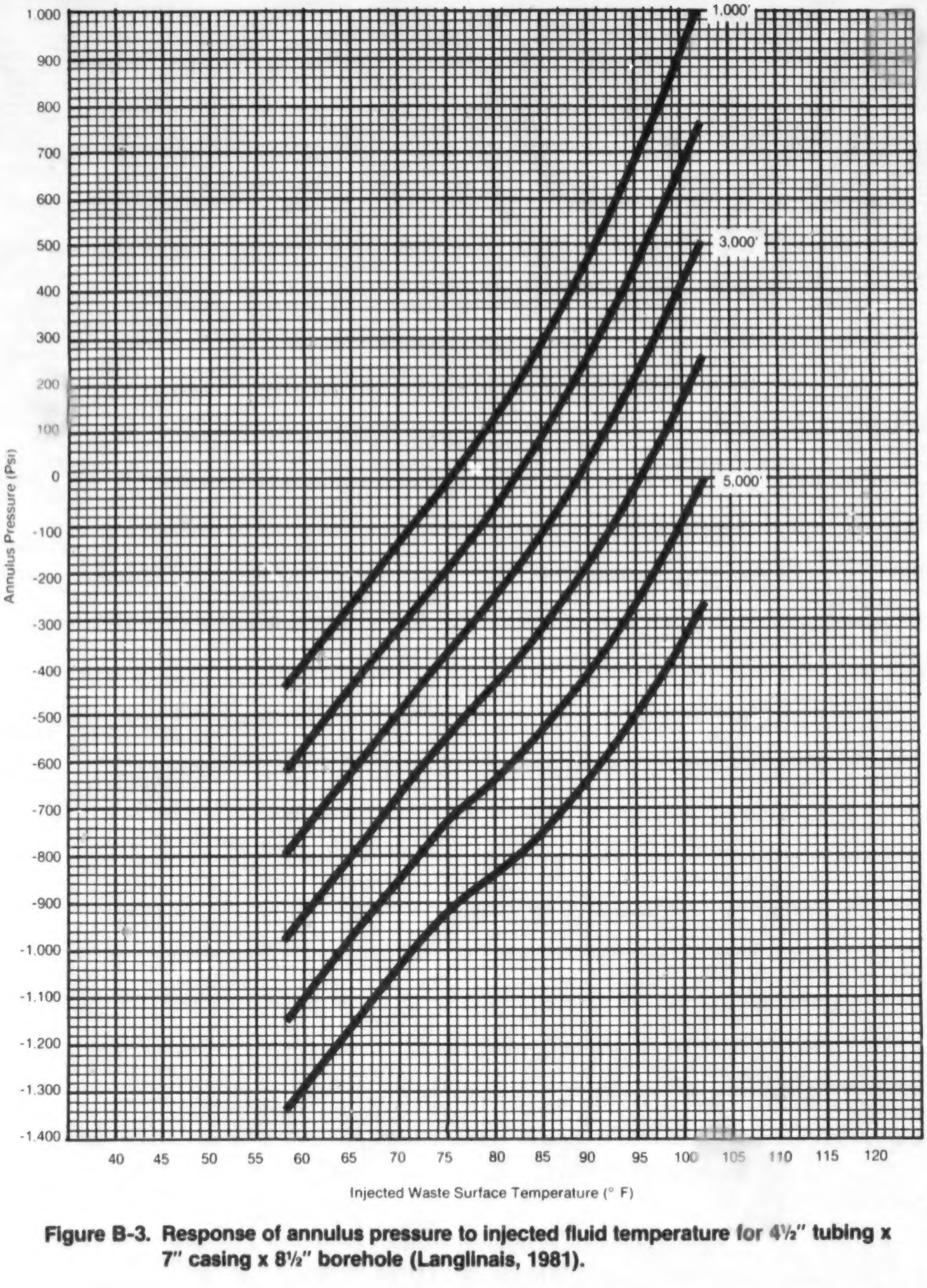

Figure B-3. Response of annulus pressure to injected fluid temperature for 4½" tubing x 7" casing x 8½" borehole (Langlinais, 1981).

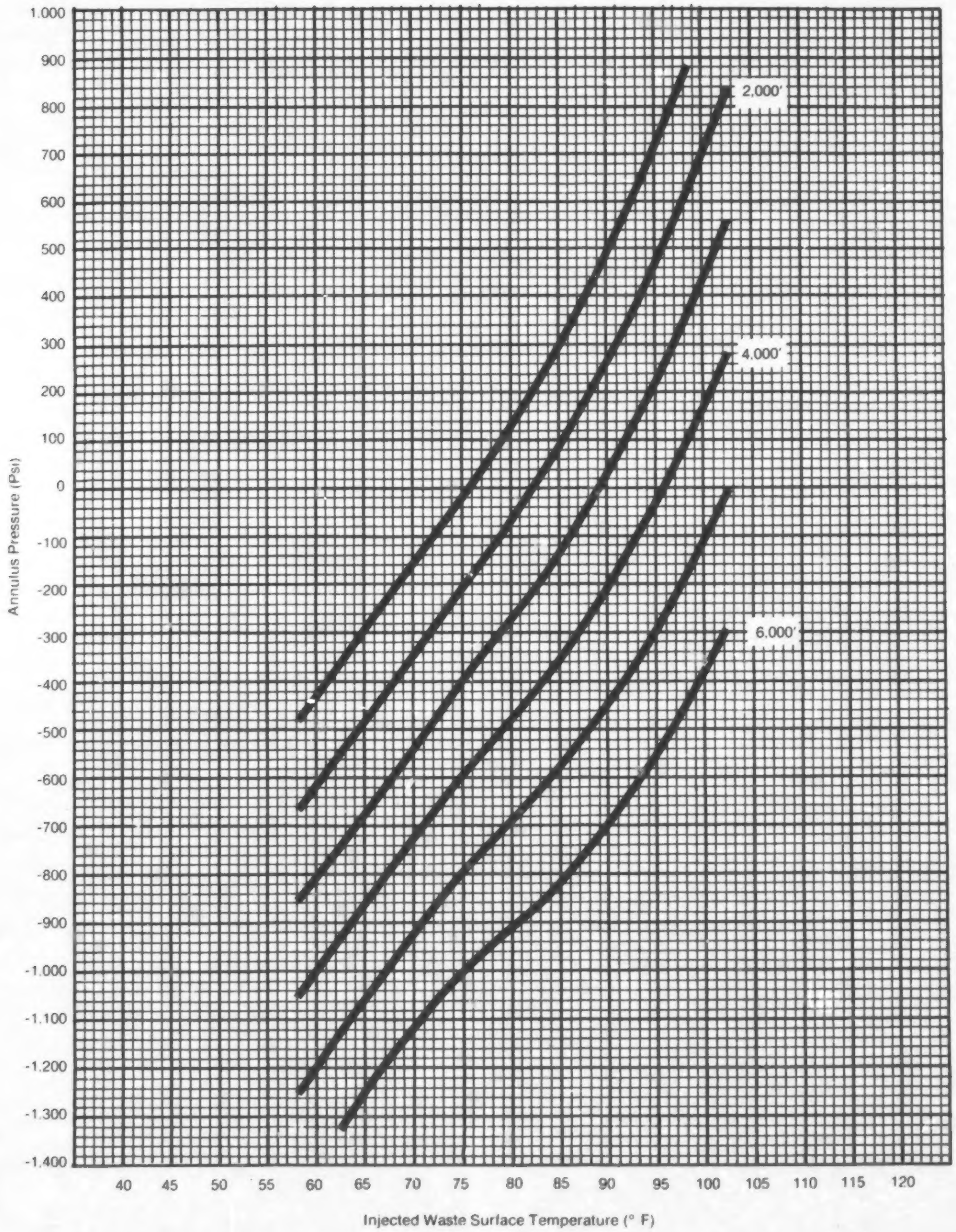

Figure B-4. Response of annulus pressure to injected fluid temperature for 4" tubing x 7" casing x 8½" borehole (Langlinais, 1981).

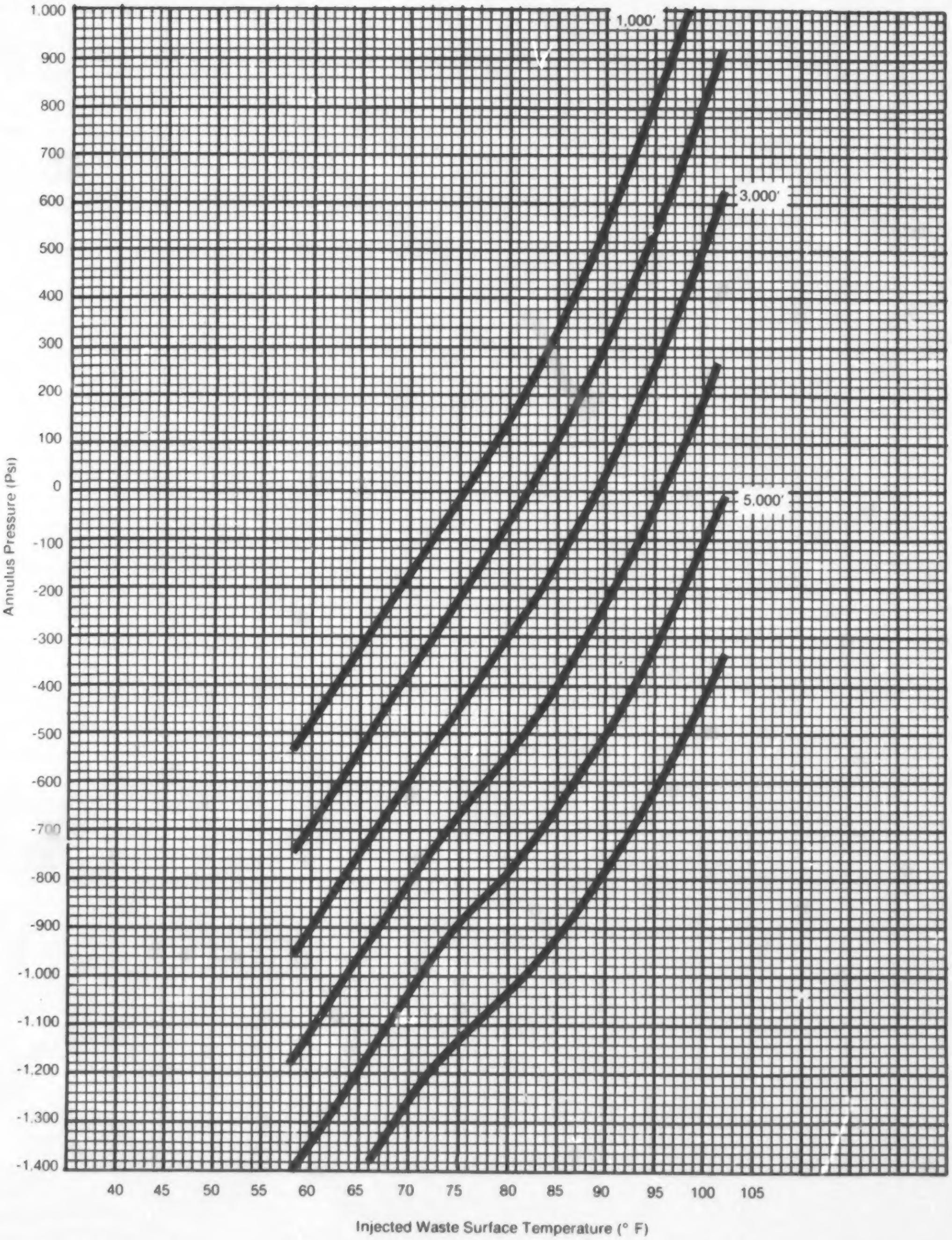

Figure B-5. Response of annulus pressure to injected fluid temperature for 2⅜" tubing x 5" casing x 6⅛" borehole (Langlinais, 1981).

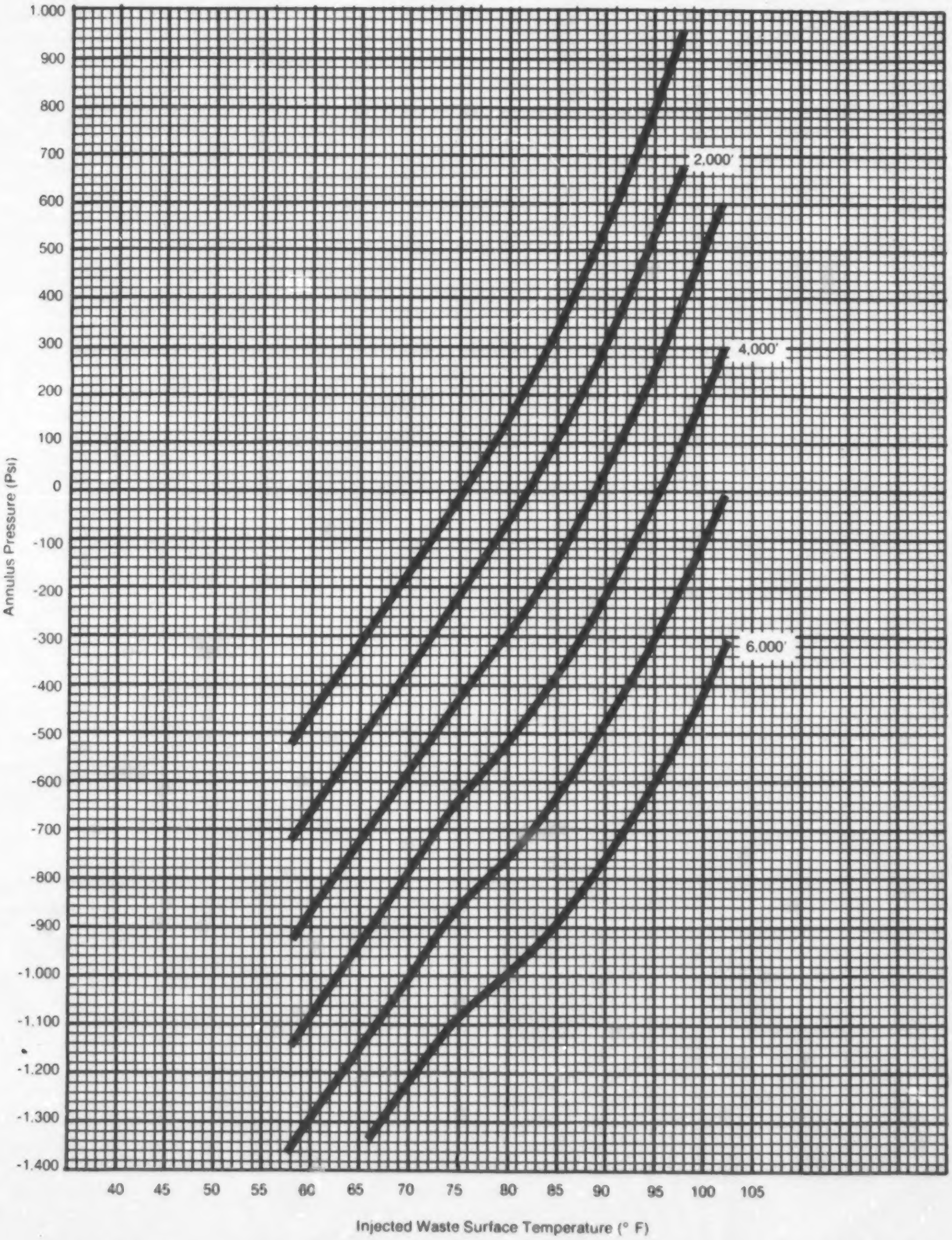

Figure B-6. **Response of annulus pressure to injected fluid temperature for 2⅞" tubing x 5½" casing x 6¾" borehole (Langlinais, 1981).**

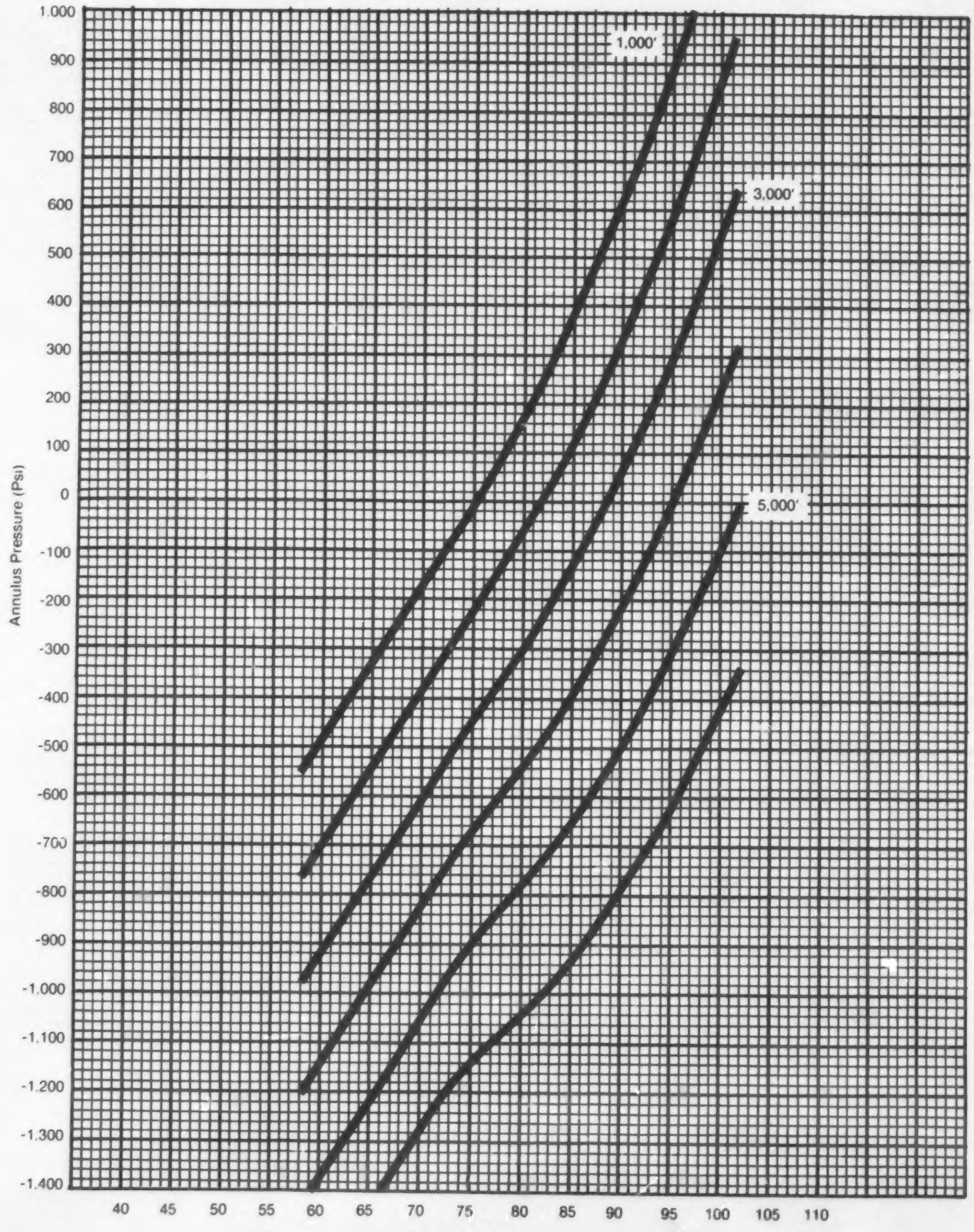

Figure B-7. Response of annulus pressure to injected fluid temperature for 2⅜" tubing x 7" casing x 8½" borehole (Langlinais, 1981).

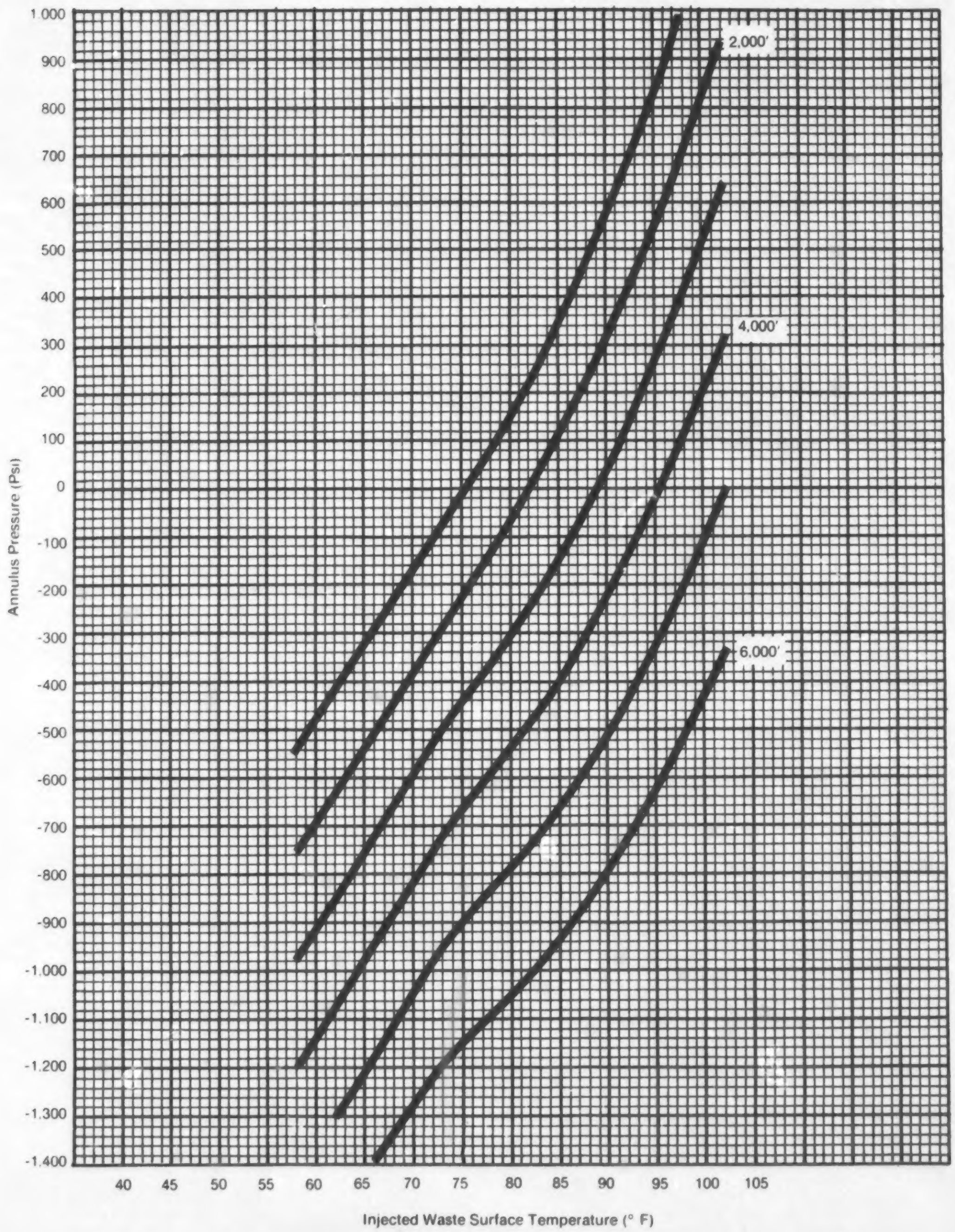

Figure B-8. Response of annulus pressure to injected fluid temperature for 2⅞" tubing x 5½" casing x 6¾" borehole (Langlinais, 1981).

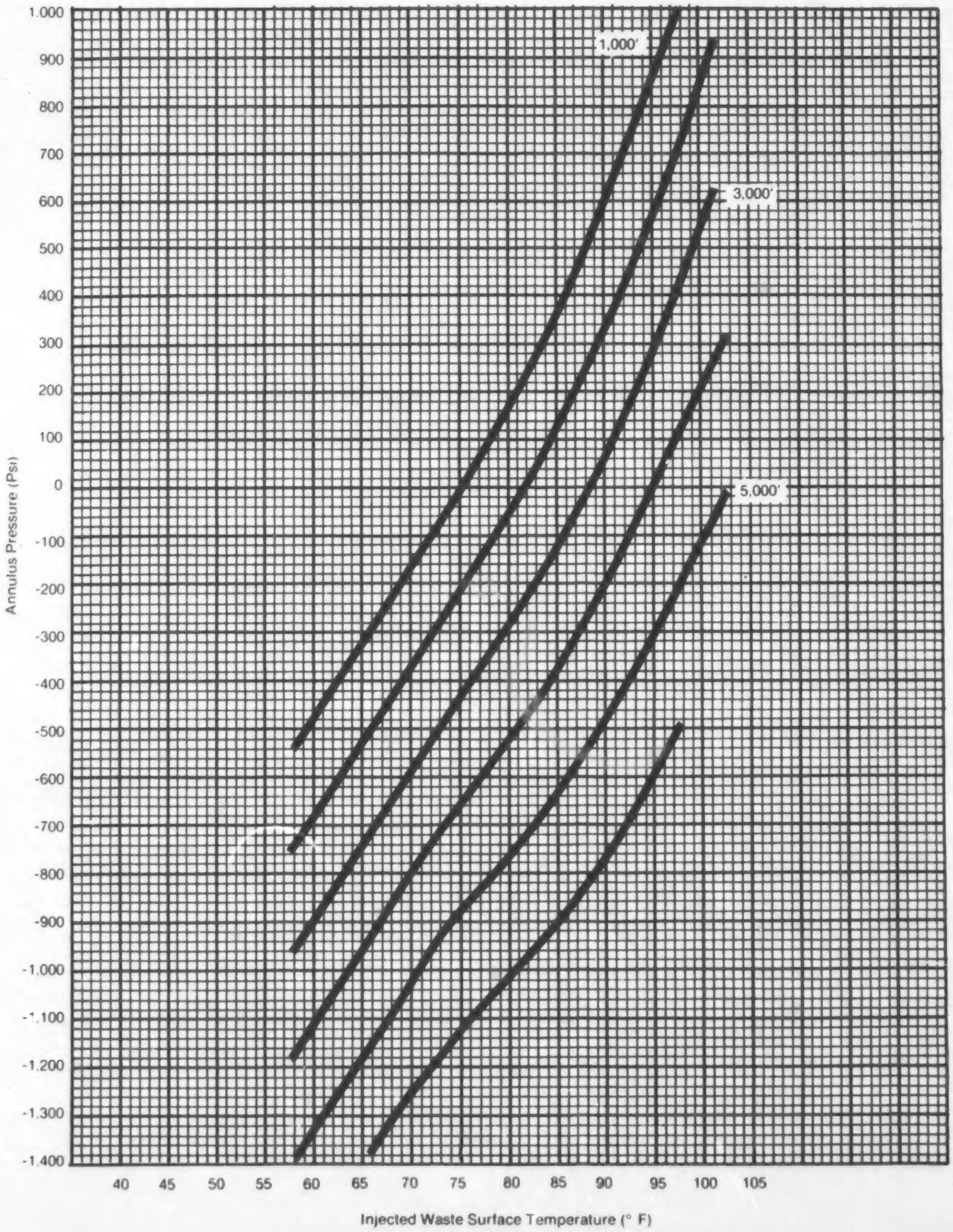

Figure B-9. Response of annulus pressure to injected fluid temperature for 2⅞" tubing x 7" casing x 8½" borehole (Langlinais, 1981).